Smith, Claudia

From: Smith, Claudia
Sent: Tuesday, April 04, 2017 7:29 AM
Subject: Notice of Issuance of Permit to Construct on the Uintah and Ouray Indian Reservation

This is to notify you that the EPA has issued a final Clean Air Act (CAA) synthetic minor permit to construct for the existing Anadarko Uintah Midstream, LLC, Cottonwood Wash Compressor Station pursuant to the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49. The final MNSR permit and response to comments can be accessed shortly in PDF format on our website at: http://www.epa.gov/caa-permitting/caa-permits-issued-epa-region-8.

In accordance with the regulations at §49.159(a), the permit will be effective 30 days after the date of this notice, on May 4, 2017. Within 30 days after a final permit decision has been issued, any person who filed comments on the proposed permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) to review any condition of the permit decision. The 30-day period within which a person may request review under this section begins when we have fulfilled the notice requirements for the final permit decision. Motions to reconsider a final order by the EAB must be filed within 10 days after service of the final order. A petition to the EAB is under Section 307(b) of the CAA, a prerequisite to seeking judicial review of the final agency action. For purposes of judicial review, final agency action occurs when we issue or deny a final permit and agency review procedures are exhausted.

Thank you,

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
****

Smith, Claudia

From:	Smith, Claudia
Sent:	Tuesday, April 04, 2017 7:29 AM
To:	Schlichtemeier, Chad (Chad.Schlichtemeier@anadarko.com)
Cc:	'mike.weaver@anadarko.com'; Ohlhausen, Natalie (Natalie.Ohlhausen@anadarko.com); Minnie Grant; Bruce Pargeets
Subject:	Final SMNSR Permit for Cottonwood Wash Compressor Station
Attachments:	Anadarko Cottonwood Wash RTC & Final Permit SMNSR-UO-000007-2012 001.pdf

Chad,

I have attached the final requested permit and the accompanying response to comments document for the Cottonwood Wash Compressor Station issued pursuant to the Tribal Minor New Source Review (MNSR) Program at 40 CFR Part 49. We will also be posting the final MNSR permit and response to comments in PDF format on our website at: http://www.epa.gov/caa-permitting/caa-permits-issued-epa-region-8.

In accordance with the regulations at §49.159(a), the permit will be effective 30 days after the date of this notice, on May 4, 2017. Within 30 days after a final permit decision has been issued, any person who filed comments on the proposed permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) to review any condition of the permit decision. The 30-day period within which a person may request review under this section begins when we have fulfilled the notice requirements for the final permit decision. Motions to reconsider a final order by the EAB must be filed within 10 days after service of the final order. A petition to the EAB is under Section 307(b) of the CAA, a prerequisite to seeking judicial review of the final agency action. For purposes of judicial review, final agency action occurs when we issue or deny a final permit and agency review procedures are exhausted.

*Note that Monica Morales signed the permit on April 3, 2017. To allow Anadarko the full 30 days required for review during the appeal period, I have set the effective date to May 4, 2017, as I was unable to send it to you until today.

If you have any questions or concerns regarding this final permit action, or would like a paper copy, please contact me.

Thank you,

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
****

Smith, Claudia

From: Schlichtemeier, Chad <Chad.Schlichtemeier@anadarko.com>
Sent: Wednesday, January 25, 2017 8:29 AM
To: Smith, Claudia
Cc: Schlichtemeier, Chad
Subject: RE: APC Comments - Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station

Claudia,

That letter was originally marked CBI but we are not making a claim for CBI for this document.

Thanks, Chad

Chad Schlichtemeier
Rockies Air Manager
Anadarko Petroleum Corporation
Office 720/929-6867
Cell 307/631-2134

From: Smith, Claudia [mailto:Smith.Claudia@epa.gov]
Sent: Wednesday, January 25, 2017 8:22 AM
To: Schlichtemeier, Chad
Cc: minnieg@utetribe.com; Bruce Pargeets; Fallon, Gail
Subject: RE: APC Comments - Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station

Chad,

In going through the comments, I noticed that page 25 of the PDF contains a Confidential Business Information stamp. Can you confirm whether or not Anadarko is making a claim of confidentiality for the document?

Thank you,

Claudia

From: Schlichtemeier, Chad [mailto:Chad.Schlichtemeier@anadarko.com]
Sent: Monday, January 09, 2017 3:26 PM
To: Smith, Claudia <Smith.Claudia@epa.gov>; R8AirPermitting <R8AirPermitting@epa.gov>
Cc: minnieg@utetribe.com; Bruce Pargeets <bpargeets@utetribe.com>; Fallon, Gail <fallon.gail@epa.gov>; Schlichtemeier, Chad <Chad.Schlichtemeier@anadarko.com>
Subject: APC Comments - Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station

Claudia,

Attached are APC's comments on the proposed permit.

Please let me know if you have any questions.

Thanks, Chad

Chad Schlichtemeier
Rockies Air Manager
Anadarko Petroleum Corporation
Office 720/929-6867
Cell 307/631-2134

From: Smith, Claudia [mailto:Smith.Claudia@epa.gov]
Sent: Thursday, December 08, 2016 4:54 PM
To: Weaver, Mike
Cc: minnieg@utetribe.com; Bruce Pargeets; Fallon, Gail; Schlichtemeier, Chad; Ohlhausen, Natalie
Subject: Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station

I have attached the requested proposed permit, the accompanying technical support document, and the bulletin board notice for the Cottonwood Wash Compressor Station. We will also be posting the proposed permit, technical support document, application and other supporting permit information in PDF format on our website at http://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8 by the start of the public comment period.

In accordance with the regulations at 40 CFR 49.157 and 49.158, we are providing a 30-day period from December 9, 2016 to January 9, 2017 for public comment on this proposed permit. Comments must be received by 5:00pm MT January 9, 2017, to be considered in the issuance of the final permit.

Please submit any written comments you may have concerning the terms and conditions of this permit. You can send them directly to me at smith.claudia@epa.gov, or to r8airpermitting@epa.gov. Should the EPA not accept any or all of these comments, you will be notified in writing and will be provided with the reasons for not accepting them.

Thank you,

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
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Smith, Claudia

From:	Schlichtemeier, Chad <Chad.Schlichtemeier@anadarko.com>
Sent:	Monday, January 09, 2017 3:26 PM
To:	Smith, Claudia; R8AirPermitting
Cc:	minnieg@utetribe.com; Bruce Pargeets; Fallon, Gail; Schlichtemeier, Chad
Subject:	APC Comments - Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station
Attachments:	EPA draft permit Cottonwood Compressor Station - APC comments 1_9_17.pdf
Follow Up Flag:	Follow up
Flag Status:	Flagged

Claudia,

Attached are APC's comments on the proposed permit.

Please let me know if you have any questions.

Thanks, Chad

Chad Schlichtemeier
Rockies Air Manager
Anadarko Petroleum Corporation
Office 720/929-6867
Cell 307/631-2134

From: Smith, Claudia [mailto:Smith.Claudia@epa.gov]
Sent: Thursday, December 08, 2016 4:54 PM
To: Weaver, Mike
Cc: minnieg@utetribe.com; Bruce Pargeets; Fallon, Gail; Schlichtemeier, Chad; Ohlhausen, Natalie
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Please submit any written comments you may have concerning the terms and conditions of this permit. You can send them directly to me at smith.claudia@epa.gov, or to r8airpermitting@epa.gov. Should the EPA not accept any or all of these comments, you will be notified in writing and will be provided with the reasons for not accepting them.

Thank you,

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
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Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
****

Anadarko
Uintah Midstream LLC

P.O. Box 173779
Denver, CO 80217-3779
720.929.6000

Sent Via Email: smith.claudia@epa.gov and r8airpermitting@epa.gov

January 9, 2017

Claudia Young Smith
United States EPA, Region 8
Air and Radiation Program, 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Proposed Permit: Cottonwood Compressor Station
Permit # SMNSR-UO-000007-2012.001

Ms. Smith

Thank you for the opportunity to provide comments on the proposed permit for the Cottonwood Compressor Station. The comment letter is presented in two (2) sections. The first section outlines the objectives of the permit with some high level comments and the second section provides specific comments on the proposed conditions.

I – Permit Objectives

1. Establish enforceable requirements for installation and operation of a catalytic control system on natural gas-fired 4-stroke lean-burn (4SLB) reciprocating internal combustion engines (RICE) to recognize the facility as a synthetic minor for carbon monoxide (CO) emissions.
    - The Cottonwood Compressor Station is a true minor for all other pollutants. Therefore, APC is only requesting CO limits to be established for the compressor engines.
    - All engines at this facility are required to comply with 40 CFR Part 63 ZZZZ (ZZZZ). It is APC's understanding that EPA is including the ZZZZ language for temperature and pressure drop monitoring as conditions of the permit due to synthetic minor for CO with no intent to change the requirements of ZZZZ. Adding conditions that are redundant are unnecessary and unless word-for-word can lead to different interpretations. APC has reviewed the conditions for consistency but given the format it is difficult in all cases to determine whether the paraphrasing has the same meaning as the CFR citation. One example of the consistency issue is the proposed conditions require monitoring every 30 days (see conditions 5 (c) and (d)) where the rule requires monitoring monthly. On the surface this seems pretty benign but in application could result 2 readings required per month (e.g. months greater than 30 days) or no readings (i.e. February 28 or 29 days). Also, if the rule is modified having conditions in the permit could result in having to comply with 2 sets of regulations until the permit is modified. APC's position is the discussion on continuous compliance belongs in the statement of basis. Adding conditions to a permit that a source is already required to comply with does not ensure a higher level of compliance. If EPA determines the requirements of ZZZZ need to be part of this permit, APC suggests one of the following:
        - That the conditions are removed and the rule is attached as an appendix to the permit <u>or</u>
        - Revise the conditions to reference the applicable sections out of ZZZZ. APC has added proposed permit condition language in Section II. If conditions remain in the final permit, APC request confirmation that the

intent of the ZZZZ conditions is to mirror the requirements of ZZZZ and compliance with ZZZZ will constitute compliance with the ZZZZ conditions in the permit.

2. Incorporate the requirements of the March 27, 2008 Consent Decree (CD) with the intent of termination.
   - APC is requesting the requirements for the low-emissions dehydrator, water storage tanks/flare and pneumatic controllers be incorporated into this permit.
   - This facility is a true minor for VOC emissions and, therefore, APC is not requesting throughput, emissions, monitoring and/or recordkeeping requirements not listed in the CD unless specifically requested by APC.
   - This is one of several permits that need to be issued before the CD can be terminated. APC requests that the requirements for the low-emissions dehydrator, water storage tanks and pneumatic controllers proposed in this permit are effective upon termination of the CD.

II – Permit Conditions

C. Requirements for the Low-Emission Dehydrator

1. Construction and Operational Limits

(a) The Permittee shall install, operate, and maintain no more than one (1) TEG Low-Emission Dehydrator meeting the following specifications:

~~(i) Limited to a maximum throughput of 85 million standard cubic feet per day (MMscfd) of natural gas;~~

APC Comment: Low-Emission Dehydrator emissions are not a function of throughput but design. Emissions are less than 1 tpy VOC for any size. Not requesting synthetic minor for VOC and throughput limitation is not a requirement of CD, therefore, request to be removed.

(ii) ~~Certified as a "Low-Emission Dehydrator" that:~~
~~(A) Incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function;~~
~~(B) Either returns the captured vapors to the inlet of the facility where the dehydrator is located or routes the captured vapors to the facility's fuel gas supply header; and~~
~~(C) Meets the control and operational requirements specified in this permit.~~
~~(b) Only the dehydration unit that is operated and controlled as specified in this permit is approved for installation and operation under this permit.~~

APC Comment: Language in 1 (a)(ii) is slightly different than the CD language. For consistency going forward, APC requests the language below from the CD. Attached is the May 26, 2006 letter documenting the existing low-emission dehydrator meets the requirement of 1 (a)(ii)

(ii) "Low-Emission Dehydrator shall meet the specifications set forth in Appendix C (attached) and shall mean a dehydration unit that:

- Incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function;
- Either returns the captured vapors to the inlet of the facility where such dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and

- Has a PTE less than 1.0 TPY of VOCs, inclusive of VOC emissions from the reboiler burner.

2~~. Emission Limits:~~
~~(a) Emissions from the Low-Emission Dehydrator shall not exceed 1.0 tons of VOC in any consecutive 12-month period.~~
~~(b) Emission limits shall apply at all times, unless otherwise specified in this permit.~~
~~3. Emissions Calculation Requirements~~
~~(a) VOC emissions for the Low Emission Dehydrator shall be calculated, in tons, and recorded at the end of each month, beginning with the first calendar month that this permit is effective.~~
~~(b) Prior to 12 full months of VOC emissions calculations, the Permittee must, within 7 calendars days of the end of each month, add the emissions for that month to the calculated emissions for all previous months since production commenced and record the total. Thereafter, the Permittee must, within seven 7 calendars days of the end of each month, add the emissions for that month to the calculated emissions for the preceding 11 months and record a new 12-month total.~~
~~(c) VOC emissions shall be calculated, in tons, using a generally accepted simulation model or software (examples include ProMax and GRI-GLYCalcTM Version 4.0 or higher). Inputs to the model shall be representative of actual average monthly operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1).~~

> **APC Comment:** By meeting the requirements of 1(a)(ii) from the CD, the emissions are less than 1 tpy VOC by design. Calculation of emissions is not required by CD and, therefore, APC requests 2. Emission Limits be removed.

4. ~~Control and Operational Requirements~~
~~(a) The Permittee shall route all non-condensable emissions from the Low Emission Dehydrator process vent and flash tank through a closed-vent system to a vapor recovery unit (VRU) with reciprocating or scroll compressors.~~
~~(b) The Low Emission Dehydrator and VRU system shall have at least three (3) levels of protection to prevent VOC emissions from occurring:~~
~~(i) Physical electrical hard-wiring between the VRU compressor(s) and the TEG circulation pump employed to ensure that if the VRU ceases to operate, the TEG~~
~~6~~
~~pump also shuts down, thereby halting the circulation of TEG through the wet gas and preventing emissions associated with the regeneration of the TEG;~~
~~(ii) A second level of protection (redundancy) is incorporated into a Programmable Logic Controller that uses instrumentation to shut down the Low Emission Dehydrator in the event the VRU compressor ceases to operate; and~~
~~(iii) A third level of protection pumps the non-condensable gases from the Low Emission Dehydrator exclusively to the station inlet or fuel system for use as fuel and ensures it is not used for blanket gas in storage tanks or otherwise vented to the atmosphere.~~

> **APC Comment:** Appendix C of the CD details design requirements of the Low-Emission Dehydrator. APC has demonstrated that dehydrator meets these requirements. APC is requesting

Appendix C be included as part of the permit to ensure the design requirements remain enforceable. APC requests 4. Control and Operational Requirements be removed.

5. Monitoring Requirements

(a~~) The Permittee shall inspect the Low Emission Dehydrator and VRU on a daily basis to ensure proper operation according to the manufacturer's maintenance recommendations.~~

(b) The Permittee shall monitor ~~the closed-vent system~~ for leaks of hydrocarbon emissions from all vent lines, connections, fittings, valves, relief valves, or any other appurtenance employed to contain, collect, and transport gases, vapors, and fumes to the VRU as follows:

(i) Visit the facility on a quarterly basis to inspect ~~the closed-vent system~~ for defects that could result in air emissions and document each inspection. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. If a quarterly visit is not feasible due to sudden, infrequent, and unavoidable events (e.g. weather, road conditions), every effort shall be made to visit the facility as close to quarterly as possible;

(ii) The inspections shall be based on audio, visual, and olfactory procedures; and

(iii) Any leaks detected in the closed-vent system shall be addressed immediately unless the repair requires resources not currently available. If the resources are not available, the leak shall be repaired no later than ~~15~~ 30 days after initial detection of the leak.

APC Comment: None of the requirements of 5 (a) or (b) are included in the CD. APC does agree to the inclusion of (b)(i)-(iii) with the exception that the 15 day repair is changed to 30 days to align with OOOOa. Condition 5 (a) requires daily inspections. This facility is not a manned station and is remotely located. Therefore, APC requests 5 (a) be removed.

(c) ~~The Permittee shall install operate, and maintain a meter that continuously measures the natural gas flowrate to the Low Emission Dehydrator with an accuracy of plus or minus 2% or better. The meter shall be inspected on a monthly basis to ensure proper operation per the manufacturer's specifications.~~

~~(d) The Permittee shall convert monthly natural gas flowrate to a daily average by dividing the monthly flowrate by the number of days in the month that the Low Emission Dehydrator processed natural gas. The Permittee shall document the actual monthly average natural gas flowrate.~~

APC Comment: Conditions 5 (c) and (d) are associated with verifying throughput for the dehydrator. See APC Comment for 1(a)(i). APC requests 5 (c) and (d) be removed.

6. Recordkeeping Requirements

(a) ~~The Permittee shall document compliance with the VOC emission limits in this permit by keeping the following records:~~

~~7~~

~~(i) All manufacturer and/or vendor specifications for the Low Emission Dehydrator, VRU, closed-vent system, and any monitoring equipment, adequate to demonstrate its compliance with the requirements of this permit;~~

~~(ii) All extended wet gas analyses;~~

~~(iii) The actual monthly average natural gas flow rate; and~~

~~(iv) The total monthly and consecutive 12-month VOC emissions calculations for the Low-Emission Dehydrator.~~

> **APC Comment:** Emissions from the dehydrator are < 1 tpy VOC by design. See APC Comment for Conditions 2. APC requests Condition 6 be removed.

> **APC Comment:** APC is moving towards termination of the Kerr McGee March 27, 2008 Consent Decree. To avoid having two documents to comply with, APC requests the following condition be added making the conditions under C. Requirements for the Low-Emission Dehydrator effective upon termination of the CD.

> **Requirements under Condition C. Requirements for the Low-Emission Dehydrator shall be effective upon termination of the Kerr McGee March 27, 2008 Consent Decree**

D. Requirements for 4SLB Compressor Engines
1. Construction and Operational Requirements
(a) The Permittee shall install and operate emission controls as specified in this permit on nine (9) existing engines used for ~~natural~~ gas compression, all meeting the following specifications:

> **APC Comment:** Several places in the proposed permit there is reference to natural gas and pipeline quality. This facility compresses unprocessed gas more commonly referred to as wet gas. Gas from this facility is sent to the Chipeta Gas Plant for processing. There is no equipment present at this facility to meet a specific fuel gas requirement. Therefore, APC requests all references to natural gas and pipeline quality be removed.

(i) Operated as a 4-stroke lean-burn engine;
(ii) Gas Fired ~~with natural gas~~; and

> **APC Comment:** See APC Comment for 1(a)

(iii) Four (4) engines limited to a maximum site rating of 1,340 horsepower (hp), two (2) engines limited to a maximum site rating of 1,775 hp and ~~five (5)~~ three (3) engines limited to a maximum site rating of 2,370 hp.

> **APC Comment:** There are only three (3) 3608 engines at this facility

(b) Only the engines that are operated and controlled as specified in this permit are approved for installation under this permit.
2. Emission Limits:
(a) CO emissions from each 1,340 hp compressor engine shall not exceed 1.21 grams per hphour (g/hp-hr).
(b) CO emissions from each 1,775 hp or 2,370 hp compressor engine shall not exceed 1.63 g/hp-hr.
(c) Emission limits shall apply at all times, unless otherwise specified in this permit.

3. Control and Operational Requirements
(a) The Permittee shall install, continuously operate and maintain a catalytic control system on each engine that is capable of reducing the uncontrolled emissions of CO to meet the

emission limits specified in this permit.
(b) ~~The Permittee shall install, continuously operate and maintain temperature-sensing devices (i.e. thermocouple or resistance temperature detectors) before the catalytic control system on each engine 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 specifications or equivalent specifications developed by the Permittee or vendor.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 3 (b) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:
>
> > Temperature monitoring, installation, collection, operation, and maintenance shall be in accordance with the requirements of 40 CFR §63.6625.

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

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 3 (c) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:
>
> > Continuous compliance with catalyst temperature operating limitations and requirements shall be demonstrated in accordance with 40 CFR §63.6640.

~~(d) 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 reading taken during the initial performance test. The baseline pressure drop across the catalyst bed shall be determined at 100% ±10% of the engine load measured during the most recent performance test or portable analyzer monitoring event, as specified in this permit.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 3 (d) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:
>
> > Compliance with catalyst pressure drop operating limitations and requirements shall be demonstrated in accordance with 40 CFR §63.6640

~~(e) The Permittee shall fire each engine with natural gas only. The natural gas shall be pipeline-quality in all respects except that the CO2 concentration in the gas is not required to be within pipeline-quality.~~

> **APC Comment:** See APC comment for 1(A). APC request 2 (e) be removed.

(f) The Permittee shall follow, for each engine and its respective catalytic control system, the manufacturer's recommended maintenance schedule and procedures, or equivalent procedures developed by the Permittee or vendor, to ensure optimum performance of each engine and its respective catalytic control system.
(g) The Permittee may rebuild an existing permitted engine or replace an existing permitted engine with an engine of the same hp 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 engines that are rebuilt or replaced shall also apply to the replaced engines.
(h) The Permittee may resume operation without the catalytic control system during an engine break-in period, not to exceed 200 operating hours, for any rebuilt or replaced engines.

4. Performance Test Requirements
(a) Performance tests shall be conducted on each engine for measuring CO to demonstrate compliance with the emission limits in this permit. The performance tests shall be conducted in accordance with appropriate reference methods specified in 40 CFR part 60, Appendix A, and/or an EPA-approved American Society for Testing and Materials (ASTM) method.
(i) The initial performance tests shall be conducted within 90 calendar days after the effective date of this permit. The results of performance tests conducted prior to the effective date of this permit may be used to demonstrate compliance with the initial performance test requirements, provided the tests were conducted in an equivalent manner as the performance test requirements in this permit.
(ii) Subsequent performance tests shall be conducted semi-annually on each engine ~~within 6 months of most recent performance test~~. After compliance is demonstrated for two consecutive tests, the testing frequency shall be reduced to annually if the facilitywide CO emissions are less than 150 tons per year (tpy). Facility-wide CO emissions shall be calculated based on the results of the most recent test and assuming 8,760 hours of operation per year. If the total facility-wide CO emissions exceed 150 tpy, then the Permittee shall resume semi-annual testing.

> **APC Comment:** This facility is remote and coordinating testing with the testing company as well as all the other engines APC has to test in this area is a challenge. APC requests testing with 6 months be replace with semi-annually to provide more flexibility.

(iii) Performance tests shall be conducted within 90 calendar days of the replacement of the catalyst on each engine.
(iv) Performance tests shall be conducted within 90 calendar days of startup of all rebuilt and replacement engines.
(b) The Permittee may submit to the EPA a written request for approval of alternate test methods, but shall only use the alternate test methods after obtaining written approval from the EPA.
(c) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, processes or operational parameters immediately prior to the engine testing or during the engine testing. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. Artificially increasing an engine load to meet testing requirements is not considered engine tuning or adjustments.

(d) The Permittee shall not abort any engine tests that demonstrate non-compliance with the CO emission limits.
(e) All performance tests conducted on the engines 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 per test.
(ii) The Permittee shall measure oxygen (O2) and CO ~~and nitrogen oxides (NOX)~~ emissions in g/hp-hr at the outlet of the control device using a portable analyzer in accordance with EPA Reference Methods 3 and 10 at 40 CFR part 60, Appendix A, or ASTM method D6522-00 (2005). Measurements to determine O2 and NOX shall be made simultaneously with measurements for CO concentration. NOx measurements shall be made with a calibrated analyzer with an approved protocol. *[Note to Permittee: Although the permit does not contain NOX emission limits for the engines, NOX measurement requirements have been included as an indicator to*
ensure compliance with Condition D.4(c) above.]

> **APC Comment:** As indicated, NOx testing is being required to verify the engine hasn't been tuned specifically for CO. Since there is no limit, NOx testing with a calibrated instrument is sufficient to verify the intent of the testing. APC suggests the reference to nitrogen oxides (NOx) be removed in the first sentence of e(ii) and language is added to the end of the condition indicating a calibrated analyzer.

(iii) The Permittee shall convert g/hp-hr measurements using EPA Reference Method 19 at 40 CFR part 60, Appendix A, and the manufacturer's specific fuel consumption or measured fuel consumption and horsepower at the time of testing. The F-factor shall be calculated based on the most recent gas analysis.

> **APC Comment:** As stated, these engines are fired on field gas. Added language to calculate the F-Factor based on the most recent gas analysis.

(iv) All performance tests shall be conducted at maximum operating rate (90% to 110% of the maximum achievable load available at the time 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 written approval from the EPA.
(v) 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.).
10
(vi) 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.
(vii) Performance test plans shall be submitted to the EPA for approval 60 calendar days prior to the date the test is planned.
(viii) 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.
(ix) 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).
(f) 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 if the testing cannot be performed.
(g) If a permitted engine is not operating, the Permittee does not need to start up the engine solely to conduct the performance test. The Permittee may conduct the performance test when the engine is started up again.

5. Monitoring Requirements
(a) ~~The Permittee shall monitor the engine exhaust temperature at the inlet to each catalyst bed.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 5 (a) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:
>
> > The Permittee shall monitor the engine exhaust temperature at the inlet to each catalyst bed as required in 40 CFR §63.6625 and 40 CFR §63.6640.

~~(b) Except during startups, which shall not exceed 30 minutes, if the engine exhaust temperature at the inlet to the catalyst bed on any engine deviates from the acceptable range 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~~
~~11~~
~~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 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's 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 range for that engine; and~~
~~(B) The catalytic control system has been repaired or replaced, if necessary.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 5 (b) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:
>
> > Except during startups, which shall not exceed 30 minutes, if the engine exhaust temperature at the inlet to the catalyst bed on any engine deviates from the acceptable range specified in this permit, the deviation shall be reported in accordance with 40 CFR §63.6640 and 40 CFR §63.6650.

~~(c) The Permittee shall monitor the pressure drop across the catalyst bed on each engine every 30 days~~ **monthly**~~, using pressure sensing devices before and after the catalyst bed to obtain a direct reading of 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~~ **monthly** ~~from the date of the initial performance test. Thereafter, the Permittee shall measure the pressure drop across each catalyst bed, at a minimum, every 30 days~~ **monthly**~~. 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~~ **monthly** ~~window. The pressure drop reading can be a one-time measurement on that day, the average of performance test runs performed on that day, or an average of all the measurements on that day if continuous readings are taken.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Condition 5 (c) and (d) are unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the conditions are revised as follows:
>
> > The Permittee shall monitor the pressure drop across the catalyst bed on each engine monthly, using pressure sensing devices before and after the catalyst bed to obtain a direct reading of the differential pressure as required in 40 CFR §63.6625 and 40 CFR §63.6640.

~~(e) If the pressure drop exceeds ± 2 inches of water from the baseline pressure drop reading taken during the most recent performance test, 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, 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 can be corrected by following the catalytic control system manufacturer's recommended procedures or equivalent~~
~~12~~
~~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 cannot be corrected using the catalytic control system manufacturer's 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 emission limits are being met and to re-establish the pressure drop across the catalyst bed. The Permittee shall perform a portable analyzer test to 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. Corrective action may include removal and cleaning of the catalyst or replacement of the catalyst.~~

APC Comment: ZZZZ requirement – As discussed, APC's position is that Condition 5 (e) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:

If the pressure drop exceeds ± 2 inches of water from the baseline pressure drop reading taken during the most recent performance test, the deviation shall be reported in accordance with 40 CFR §63.6640 and 40 CFR §63.6650

~~(f) The Permittee is not required to conduct parametric monitoring of exhaust temperature and catalyst differential pressure on an engine if it has not operated during the monitoring period. The Permittee shall certify that the engine did not operate during the monitoring period in the annual report specified in this permit.~~

APC Comment: ZZZZ requirement – As discussed, APC's position is that Condition 5 (f) is unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the condition is revised as follows:

The Permittee is not required to conduct parametric monitoring of exhaust temperature and catalyst differential pressure on an engine if it has not operated during the monitoring period. The Permittee shall certify that the engine did not operate during the monitoring period in the annual report specified in this permit.

6. Recordkeeping Requirements
(a) Records shall be kept of manufacturer and/or vendor specifications for each engine, catalytic control system, temperature-sensing device and pressure-measuring device.

(b) Records shall be kept of all calibration and maintenance conducted for each engine, catalytic control system, temperature-sensing device and pressure-measuring device.
(c) ~~Records shall be kept that are sufficient to demonstrate that the fuel for each engine is pipeline quality natural gas in all respects, with the exception of CO2 concentrations.~~

> **APC Comment:** See APC Comment for D 1. (a). APC request 6.(c) be removed.

(d) ~~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.~~
~~(e) 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.~~

> **APC Comment:** ZZZZ requirement – As discussed, APC's position is that Conditions 6 (d) and (e) are unnecessary and should be removed. If EPA determines the requirements of ZZZZ need to be part of this permit, APC requests that either the rule is attached as an appendix to the permit or the conditions are revised as follows:
>
> > 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 in accordance with 40 CFR §63.6655.
> >
> > 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 in accordance with 40 CFR §63.6655.

(f) Records shall be kept of all required testing 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;
13
(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.
(g) Records shall be kept of all catalyst replacements, engine rebuilds and engine replacements.
(h) Records shall be kept of each rebuilt or replaced engine break-in period, pursuant to the requirements of this permit, where the existing engine that has been rebuilt resumes operation without the catalyst control system, for a period not to exceed 200 hours.
(i) Records shall be kept of each time an engine is shut down due to a deviation in the inlet temperature to the catalyst bed or pressure drop across a 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.

E. Requirements for Storage Tanks
1. Construction, Control and Operational Requirements
(a) ~~The Permittee shall install, operate, and maintain no more than three (3) tanks used to store natural gas condensate and produced water, each limited to a maximum storage capacity of 400 barrels (bbl);~~

APC Comment: In 2011, a new inlet slug catcher system was installed. Part of system was a blow case. The blow case takes condensate recovered in the slug catcher and sends it down the pipeline for processing. The slug catcher is currently not 100 percent effective in removing the condensate from the water. The water tanks currently receive condensate carry over from the inlet slug catcher. These tanks are primarily used for water storage and the blow case is the primary process for removing condensate from the facility. As mentioned, this facility is remote and specifying the number and size of tanks limits flexibility. There could be a need to install more tanks or different sizes due to trucking limitations. Controlled emissions are reported a 1 tpy VOC. Condition 4(a) requires all tanks to be controlled. The number and size has no impact on emissions. APC requests E 1(a) be removed.

(b) The Permittee shall, at a minimum, route all natural gas condensate and produced water storage tank emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare designed and operated as specified in this permit.
(c) Only the storage tanks that are operated and controlled as specified in this permit are approved for installation under this permit.
2. ~~Production Limit: The total condensate and produced water processed through the storage tanks shall not exceed 13 barrels per day on average.~~

APC Comment: This facility is a true minor for VOCs and therefore only requesting to incorporate conditions from the CD. Estimated emissions are based on 13 bbls/day of condensate only and are estimated at 1tpy VOC. APC request 2. Production Limit be removed.

3. Closed-Vent Systems
(a) ~~The Permittee shall design, install, continuously operate and maintain each closed-vent system such that it is compliant with the following requirements:~~
~~(i) The closed-vent system shall route all gases, vapors, and fumes emitted from the natural gas condensate and produced water storage tanks to the flare;~~
~~(ii) All vent lines, connections, fittings, valves, relief valves or any other appurtenance employed to contain and collect gases, vapors, and fumes and transport them to the flare shall be maintained and operated during any time the device is operating;~~
~~(iii) The closed-vent system shall be designed to operate with no detectable emissions;~~
~~14~~
~~(iv) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the flare, the Permittee shall meet the one of following requirements for each bypass device:~~
~~(A) At the inlet to the bypass device that could divert the stream away from the flare and into the atmosphere, properly install, calibrate, maintain and operate a flow indicator that is capable of taking periodic readings and sounding an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the flare and into the atmosphere;~~
~~or~~
~~(B) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.~~
~~(v) The Permittee shall minimize leaks of hydrocarbon emissions from all vent lines, connections, fittings, valves, relief valves or any other appurtenance employed to~~

~~contain, collect, and transport gases, vapors, and fumes to the flare.~~

> **APC Comment:** The tank control system was designed per the CD. Condition 3 (a) is not covered in the CD and APC request to be removed.

4. Flare
(a) The Permittee shall design, install, continuously operate and maintain a flare such that the mass content of the uncontrolled VOC emissions from the natural gas condensate and produced water storage tanks are reduced by at least 95.0 percent by weight.
(b) ~~The Permittee shall ensure that the flare has sufficient capacity to achieve at least a 95.0 percent VOC emission control efficiency for the minimum and maximum hydrocarbon volumetric flow rate and BTU content routed to the device.~~

> **APC Comment:** As stated, the tank control system was designed per the CD. Condition 4 (a) addresses controlling emissions from the tanks. Condition 4 (b) is not covered in the CD and APC request to be removed.

(c) The Permittee shall ensure that the flare is designed and operated in accordance with the requirements of 40 CFR 60.18(c) through (e).
(d) The Permittee shall ensure that the flare is:
(i) Operated properly at all times that natural gas condensate and produced water storage tank emissions are routed to it;
(ii) ~~Equipped and operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the 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 <u>with a thermocouple that reignites the pilot flame whenever it goes out a malfunction alarm</u> ~~and notification system if the pilot flame fails while natural gas condensate and produced water storage tank emissions are routed to it;~~
~~(v) Maintained in a leak-free condition; and~~
~~(vi) Operated with no visible smoke emissions.~~
~~(e) The Permittee shall follow the manufacturer's recommended maintenance schedule and operational procedures, or recommended maintenance schedule and operational procedures developed by the vendor or Permittee, to ensure optimum performance of the closed-vent systems and flare.~~

> **APC Comment:** As stated, the tank control system was designed per the CD. Condition 4 (a) addresses controlling emissions from the tanks. Conditions 4 (d) (ii), (iii), (v) and (vi) and (e) are not covered in the CD and APC request to be removed. APC request the 4(d)(iv) be revised to be consistent with the language in the CD.

5. Testing and Monitoring Requirements
(a) ~~The Permittee shall measure the barrels of natural gas condensate and produced water stored in the tanks each time the liquids are unloaded from the storage tanks using process flow meters and/or sales records. At the end of each calendar month, the total barrels of natural gas condensate and produced water stored in the tanks shall be divided by the number of days in that month to calculate a daily average.~~

APC Comment: See APC Comment 2 Production Limit. APC request 5(a) be removed.

(b) The Permittee shall perform weekly inspections as follows:
<u>(i)</u> Auditory, visual, olfactory (AVO) inspections of tank thief hatches, covers, seals, pressure relief valves and the closed vent system, to ensure proper condition and functioning. ~~The weekly inspections shall be performed while the natural gas condensate and produced water storage tanks are being filled.~~ If any of the components are not in good working condition, they must be repaired within ~~15~~ <u>30</u> days of identification of the deficient condition.
<u>(ii) Verify the pilot light on flare is lit and if the flare is being bypassed at the time of inspection.</u>
(c) The Permittee shall perform monthly visual inspections of the <u>of tank thief hatches, covers, seals, pressure relief valves and the closed vent system, to ensure proper condition and functioning.</u> ~~peak pressure and vacuum values in each tank and the closed-vent system to ensure that the pressure and vacuum relief set points are not being exceeded in a way that has resulted, or might result, in venting of emissions and possible damage to equipment, and to ensure that the closed vent system operates with no detectable emissions.~~ Monthly visual inspections shall be conducted as follows:
(i) The monthly inspections shall be performed using an optical gas imaging instrument ~~and while the natural gas condensate and produced water storage tanks are being filled~~;
(ii) If any detectable ~~or visible smoke~~ emissions are detected using the optical gas imaging instrument, <u>they must be repaired within 30 days of identification of the deficient condition</u>. ~~the Permittee shall take the following actions, as applicable:~~
~~(A) The Permittee shall demonstrate that the natural gas condensate and produced water storage tanks and the closed-vent system operate with no detectable emissions using the procedures specified in EPA Method 21 at 40 CFR part 60, Appendix A. A potential leak is determined to operate with no detectable emissions if the VOC concentration value measured by the Method 21 detection instrument is less than 500 parts per million volume (ppmv);~~
~~(B) If the closed-vent system or flare fail the detectable emissions or visual emissions test, the Permittee shall follow the manufacturer's, vendor's, or Permittee's repair instructions to return the emissions source to compliant~~
~~16~~
~~operation. All repairs and maintenance activities shall be recorded in a maintenance and repair log and shall be made available for inspection;~~
~~(C) Upon return to operation from any repair and maintenance activity, the closed-vent system or flare shall pass a Method 21 or Method 22 test, as applicable;~~
~~(D) If the closed-vent system or flare fail a follow up Method 21 or Method 22 test, the Permittee shall repeat the procedures in paragraphs (A) through (C) of this section, as applicable, until the closed-vent system or flare passes a follow up test; and~~
~~(E) The Monthly VOC emissions calculations required in this permit shall account for the time periods between each failed detectable emissions or visible emissions test, as applicable, and subsequent compliant tests,~~

~~assuming the emissions were uncontrolled.~~
~~(d) The Permittee shall monitor the operation of the flare to confirm proper operation and demonstrate compliance with the VOC control efficiency requirements of this permit as follows:~~
~~(i) Continuously monitor the flare operation, using a malfunction alarm and remote notification system for failures, and checking the system for proper operation whenever an operator is on site, at least weekly;~~
~~(ii) Continuously monitor all variable operational parameters specified in the manufacturer's written operating instructions and procedures;~~
~~(iii) Respond to any observation of improper monitoring equipment operation or any alarm of pilot flame failure and ensure that monitoring equipment is returned to proper operation and/or the pilot flame is relit as soon as practically and safely possible after an observation or an alarm sounds;~~

> **APC Comment:** The CD does not require AVO or OGI monitoring. APC is currently performing inspections as detailed in 5(b) and (c)(i) and (ii). APC accepts inclusion of 5(b) and (c)(i) and (ii) with the suggested wording changes. Conditions c(ii)(A-E) and d are not a requirement of the CD and request to be removed. The CD requires weekly inspections to verify the pilot light is lit and if the flare is being bypassed at the time of inspections.

~~(iv)~~ Perform monthly visual inspections of the flare to ensure it operates with no visible smoke emissions. Monthly visual inspections shall be conducted as follows:
~~(A) The monthly inspections shall be performed using an optical gas imaging instrument and while the natural gas condensate and produced water storage tanks are being filled;~~
(B) If any visible smoke emissions are detected ~~using the optical gas imaging instrument,~~ the Permittee shall take the following actions:
~~(I)~~ The Permittee shall demonstrate that the flare operates with no visible emissions, except for periods not to exceed a total of 2 minutes during any hour, using the procedures specified in EPA Method 22 at 40 CFR part 60, Appendix A. The observation period shall be 1 hour;

> **APC Comment:** Using OGI to determine presence of visual emissions from the flare is not required by the CD. APC request (iv)(A) be removed. APC request (iv)(B) be revised to remove the reference to optical gas imaging.

(II)-If the flare fails the visual emissions test, the Permittee shall follow the manufacturer's, vendor's, or Permittee's repair instructions to return the flare to compliant operation. All repairs and maintenance activities shall be recorded in a maintenance and repair log and shall be made available for inspection;
(III) Upon return to operation from any repair and maintenance activity, the flare shall pass a Method 22 test; and
(IV) If the flare fails a follow up Method 22 test, the Permittee shall repeat the procedures in paragraphs (I) through (III) of this section, until the flare passes a follow up test.

~~(e) The monthly VOC emissions calculations required in this permit shall account for the~~

~~time periods between each failed detectable emissions or visible emissions test, as applicable, and subsequent compliant tests, assuming the emissions were uncontrolled.~~
~~(f) Where sufficient to meet the monitoring requirements in this section, the owner or operator may use a SCADA system to monitor and record the required data in paragraphs (a) through (d).~~
~~6. VOC Emissions Calculation Requirements: VOC emissions from each natural gas condensate and produced water storage tank at the facility due to working, standing, breathing and flashing losses for each calendar month shall be calculated using a generally accepted simulation model or software (e.g., ProMax) and the following:~~
~~(a) The total measured volume of natural gas condensate and produced water transferred to the storage tanks for the month;~~
~~(b) The VOC emissions control efficiency of the flare; and~~
~~(c) The actual physical and chemical properties of the natural gas condensate and its associated vapors from the most recent semiannual extended laboratory analysis of the natural gas condensate received at the facility.~~
7. Recordkeeping Requirements: The Permittee shall document and maintain the following records:
(a) ~~The monthly and average daily barrels of condensate and produced water processed through the storage tanks;~~
(b) ~~All natural gas condensate and produced water storage tank, closed-vent system, and flare inspections. All natural gas condensate and produced water storage tank closed-vent system, and~~ Tank and flare inspection records shall include, at a minimum, the following information:
(i) The date of the inspection;
(ii) All documentation and/or images produced in the inspection;
(iii) The findings of the inspection;
(iv) Any corrective action taken; and
(v) The inspector's name and signature.
(c) ~~The monthly VOC emissions, in tons, from each natural gas condensate and produced water storage tank and the emission calculations.~~

> **APC Comment:** APC requests Conditions 7(a) be removed. See APC Comment 2 Production Limit. Wording in condition 7(b) has been revised to reflect CD monitoring requirements.
>
> **APC Comment:** As mentioned, APC is moving towards termination of the Kerr McGee March 27, 2008 Consent Decree. To avoid having two documents to comply with, APC requests the following condition be added making the conditions under Condition E. Requirements for the Storage Tanks effective upon termination of the CD.
>
> **Requirements under Condition E. Requirements for the Storage Tanks shall be effective upon termination of the Kerr McGee March 27, 2008 Consent Decree**

F. Requirements for Pneumatic Controllers
1. All pneumatic controllers shall be operated using only instrument air <u>or low-bleed controllers.</u>

> **APC Comment:** Added low-bleed controllers to be consistent with CD

2. Records shall be kept of manufacturer's and/or vendor's specifications for each pneumatic controller <u>that is not operated on instrument air.</u>

APC Comment: This information is only necessary if the controller is not operated on instrument air. APC suggest adding the additional language.

APC Comment: As mentioned, APC is moving towards termination of the Kerr McGee March 27, 2008 Consent Decree. To avoid having two documents to comply with, APC requests the following condition be added making the conditions under Condition E. Requirements for the Pneumatic Controllers effective upon termination of the CD.

Requirements under Condition F. Requirements for Pneumatic Controllers shall be effective upon termination of the Kerr McGee March 27, 2008 Consent Decree

Please feel free to call me at 720-929-6867 or e-mail me at Chad.Schlichtemeier@anadarko.com if you have any questions.

Sincerely,
ANADARKO UINTAH MIDSTREAM, LLC

Chad Schlichtemeier
HSE Manager

Enclosures

APPENDIX C

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

LOW-EMISSION DEHYDRATOR SPECIFICATIONS

Overview and Purpose

Kerr-McGee has agreed to employ "Low-Emission Dehydrator" technology at its existing and planned facilities in the Uinta Basin as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.A., this Appendix C includes:

(a) a description of physical electrical hard-wiring between the vapor recovery unit ("VRU") compressor(s) and the glycol circulation pumps employed or to be employed, so that if the VRU compressor(s) go down then the glycol circulation pump(s) also shut down, thereby halting the circulation of glycol through the wet gas, as well as the emissions associated with the regeneration of the glycol;

(b) a description of a second level of protection (redundancy) incorporated into a Programmable Logic Controller that uses instrumentation to shut down the glycol dehydration system in the event all VRU compressor(s) go down; and

(c) a description of any third level of protection and discussion of how the non-condensible gases from glycol dehydrator operation shall be piped exclusively to the station inlet or fuel system for use as fuel and is not used for blanket gas in storage tanks or otherwise vented.

Background

Natural gas often contains water vapor at the wellhead which must be removed to avoid pipeline corrosion and solid hydrate formation. Glycol dehydration is the most widely used natural gas dehumidification process. In a glycol dehydration system, dry triethylene glycol ("TEG") or ethylene glycol ("EG") is contacted with wet natural gas. The glycol absorbs water from the natural gas, but also absorbs hydrocarbons including volatile organic compounds ("VOCs") and certain hazardous air pollutants ("HAPs"). Pumps circulate the glycol from a low-pressure distillation column for regeneration back to high pressure in order to contact with the high pressure wet gas. As the wet glycol pressure is reduced prior to distillation, much of the absorbed hydrocarbon is released, including some of the VOCs and HAPs. A flash tank is typically utilized to separate these vapors at a pressure where they can be utilized for fuel. Distillation removes the absorbed water along with any remaining hydrocarbon, including VOCs and HAPs, from the glycol to the still column vent as overhead vapor. Conventional dehydrator still columns often emit the non-condensable portion of this overhead vapor directly to the atmosphere, or to a combustion device such as a thermal oxidizer or reboiler burner.

Kerr-McGee currently utilizes low-emission glycol dehydrators at its facilities in the Uinta Basin. These units capture the non-condensable portion of still vent and flash tank vapors and recompress the vapor with reciprocating or scroll compressors that route the

vapor to the station inlet as natural gas product, to fuel lines for power generation turbines or to the station fuel system. They also employ electric glycol circulation pumps, and except for the recompression of non-condensable vapors, resemble conventional glycol dehydrators in their configuration. See Figure 1.

To insure that the non-condensable vapor compression system is fully integrated into dehydrator operation such that the units cannot be disabled so as to operate while venting to the atmosphere, each unit;

a. incorporates an integral vapor recovery function that prevents the dehydrator from operating independent of the vapor recovery function;
b. either returns the captured vapors to the inlet of the facility where each glycol dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and
c. thereby emits no more than 1.0 ton per year of VOCs.

Description of Interlocks

The low-emission glycol dehydrators have at least three (3) levels of protection to prevent emissions from occurring.

(a) Physical electrical hard-wiring between the vapor recovery unit (VRU) compressor(s) and the glycol circulation pumps ensures that if the VRU compressor(s) goes down, the glycol pump(s) also shut down, thereby halting the circulation of glycol through the wet gas as well as the emissions associated with the regeneration of glycol. More specifically:

1. Loss of station power interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor.
2. Loss of 24 volt power to a relay interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor. The 24 volt power is wired in parallel through the run status contacts of each VRU compressor in a specific service. If all VRU compressors in each specific service are shutdown, the 24 volt power is interrupted. There is at least one spare VRU compressor in standby mode for each specific service at existing Uinta Basin facilities engaged in gas dehydration. Non-condensable gas from VRU compressor discharge always has an outlet because if the station inlet pressure rises to a level greater than VRU compressor output, the flash tank vapors automatically go through a back pressure regulator to the fuel gas system until gathering pressure is reduced.
3. If the glycol still column/reboiler pressure rises above pressure set points, the 24 volt power to a relay is interrupted. The unpowered relay interrupts the 480 volt power to the glycol pump(s) circulating glycol to the contactor. If one of the glycol still VRU compressors is running but not compressing vapors, the pressure switch will detect the pressure rise in the still and shutdown the glycol circulating pump(s).

4. The operation of at least one of the VRU compressors is required to complete the electrical circuit and allow one of the glycol circulation pumps to operate.
5. There is a 10 second time delay switch installed in the physical electrical circuit that must time out before the glycol circulating pump(s) shut down for causes 2 and 3 above. This allows for switching of compressors and helps to prevent false shutdowns.
6. Everything is hard wired and does not depend on any type of controller.

(b) A second level of protection redundancy has been incorporated by utilizing the station Programmable Logic Controller (PLC) to shut down the dehydration system in the event the VRU compressor(s) go down.

1. A PLC timer will start counting when none of the VRU compressor(s) are in operation. When the timer times out, the PLC will not allow the regenerator system to be in run status.

(c) A third level of protection is the routing of non-condensables directly to combustion devices in the stations that utilize micro-turbine electrical generators or central heat medium systems.

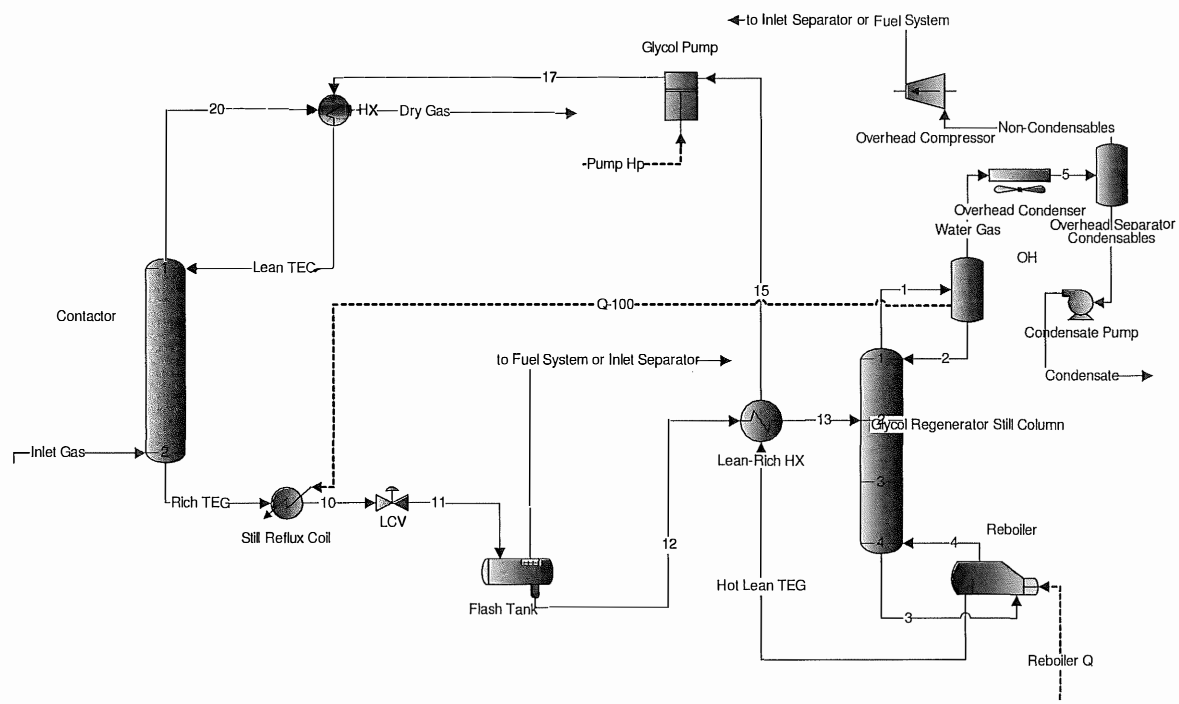
1. The non-condensable regenerator overhead vapors are routed to the inlet of each station or used as fuel. In instances where the inlet pressure rises above VRU compressor outlet pressures, a regulator opens allowing the VRU-compressed vapors to be discharged into the fuel system, where they are used throughout the station.
2. In Kerr-McGee's planned electrified compressor stations, liquids that condense at the compression stations, including those condensed from the glycol still overhead vapors, will be contained at pressure, separated from any water and pumped downstream into the high pressure gathering system. This process change will eliminate atmospheric storage of hydrocarbon liquids at such facilities.

Conclusion

Kerr-McGee's adherence to these specifications shall satisfy its commitment in the Consent Decree to utilize low-emission dehydrator technology in its existing and planned Uinta Basin operations.

Figure 1: Kerr-McGee Low-Emission Dehydrator Schematic

Glycol Dehydration Unit



Appendix C: Low-Emission Dehydrator Specifications

ELS
Copy sent
to Jacus

KerrMcGee

July 12, 2006

Kerr-McGee Oil & Gas OnShore LP
1999 Broadway, Suite 3700, Denver, Colorado 80202
303-296-3600 • Fax 303-296-3601

Ms. Kathleen Paser
Environmental Engineer
U.S. EPA
Air and Radiation Program (8P-AR)
999 18th Street, Ste. 300
Denver, CO 80202

CONFIDENTIAL BUSINESS INFORMATION

Re: Independent Engineering Evaluation
Ouray Dehydration Unit
Cottonwood Dehydration Unit
Bridge Station Dehydration Unit

Dear Ms. Paser,

Attached for your information are independent engineering evaluations conducted by Huzyk Energy Management Inc. for the three named dehydration units located in Uintah County, Utah. The purpose of the evaluations was to determine what emissions if any are associated with the operation of these new types of dehydration units. As you know, this evaluation is intended to support EPA's final issuance of Part 71 operating permits for the facilities at which these units are located.

Sandra Huzyk's analysis confirmed that our dehydrators have zero emissions of VOC's from the routing of regenerator and flash tank overheads to integrated vapor recovery units (VRU's), and that safeguards exist to ensure that the dehydrator shuts down if the VRU's are shut down for any reason. I have included a copy of Ms. Huzyk's background and qualifications at the end of the report.

If you have any questions please feel free to contact me at 720-264-2717.

Very truly yours,

Ed G. Schicktanz

Ed G. Schicktanz
Senior Staff Environmental Specialist
Kerr-McGee Oil and Gas Onshore LP

HUZYK ENERGY MANAGEMENT, INC.

Chemical Engineering and Project Management

Sandra L. Huzyk, P. E.

Mr. Ed Schicktanz
Sr. Staff Environmental Specialist
Kerr-McGee Oil & Gas Onshore, LP
1999 Broadway
Suite 3700
Denver, CO 80202

CONFIDENTIAL BUSINESS INFORMATION

May 26, 2006

Cottonwood Plant Dehydration Evaluation
<u>Uintah County, Utah</u>

Summary

I spent a couple of hours at the site observing operation of the TEG dehydration plant, questioning Mr. Gary Brom, facility engineer; and observing a test. I have concluded Cottonwood has zero-emission operation under normal conditions.

Discussion

Operation of Gas Dehydration

The attached flowsheets and mass balance provide operation and equipment detail for the discussion that follows. In each 'Inlets and Outlets' table the third entry (under temperature and pressure) is the total mass flow rate, which will provide an accurate overall mass balance. Below this entry, I have included component flow rates for VOC. You may use this to track a component mass balance for each VOC brought in with the gas. The 'Liquid Circulation' table shows BTEX absorption into the solvent, and residual values after regeneration. This table is not involved in computing the overall mass balance.

Natural gas flows from the gathering systems into inlet separation and compression. Approximately 40 mmscfd of compressed gas at 545 psig flows to the TEG contactor. It enters the contactor at the bottom, flowing upwards against downward flow of the solvent, triethylene glycol. Gas and liquid contact on the absorber trays allow the solvent to absorb water from the gas. Inlet gas has 82 # water/mmscf at the inlet, and has less than 4# water/mmscf at the outlet of the contactor.

TEG that has absorbed water is termed 'rich' glycol. Not only do glycol compounds absorb water, they absorb some heavy hydrocarbons. Rich glycol is warmer than the lean glycol entering the contactor because of heat of absorption. It flows from the contactor bottom and into the condenser coils of the regenerator, discussed later. Leaving these coils in the top of the regenerator, the glycol has been further heated to approx.105 F. Flow continues through one barrel of the rich/lean exchanger.

Here, lean glycol from the regenerator (approx. 360 deg. F) exchanges more heat with the rich flow, increasing its temp to 150 F. The heated solvent flows to the lower pressure flash tank, which allows absorbed hydrocarbons to flash off as a gas, leaving the rich glycol mostly free of hydrocarbon contamination. The separated hydrocarbon gas and liquid flow to the BTEX and vapor recovery unit.

Rich glycol flows through charcoal and sock filters that will absorb oil and solid contaminants. Once scrubbed of contaminants, the flow continues through the last two barrels of the rich/lean exchanger, picking up heat from the lean glycol out of the heater.

By now the rich glycol is well over 200 deg. F, and feeds into the regenerator. This regenerator operates at a few inches of w.c., i.e. only about 0.5 psi. The combination of this low pressure and high temperature at the bottom, boils off water and hydrocarbons, regenerating the solvent. The solvent is now termed 'lean', as it is approx. 99.5 wt. % TEG out of the heater.

Cottonwood has a particular type of regenerator, called a Coldfinger. This unit has the capability of enhancing water removal via a condensing medium (rich TEG) in addition to the stripper overhead condensing . As well, there is a connection for a stripping gas sparge. These options can get TEG purity to 99.99 wt. %, resulting in gas dried to less than 0.5 #/mmscf. They are used only occasionally.

Lean, low pressure TEG flows down through the three barrels of the rich/lean exchanger, cooling as it goes. A pump boosts the liquid to contactor pressure. From pump discharge the lean TEG is cooled finally in the glycol/gas exchanger, entering the contactor at no more than 115 deg. F.

BTEX Removal
Regenerator and flash tank overheads are a source of hydrocarbon pollution if not properly captured and processed. Regenerator overhead gas flows to the BTEX recovery unit. This unitis an air-cooled, finned-tube, natural convection exchanger, followed by a separator that catches condensed liquid. It allows vapor to flash off. BTEX is an acronym for the contaminants, benzene, toluene, ethylbenzene and xylenes (ortho, meta and para-).

Noncondensible vapor from this vessel flows to the vapor recovery unit (suction 8" w.c.). Recovery of non-condensible vapor and delivery back to field inlet or into fuel gas is the key to zero-emission operation. In general, if VRU compressors are down, a BTEX unit would overpressure and emit HC vapor to atmosphere. This would happen because the glycol pumps would keep circulating TEG and keep absorbing hydrocarbons.

Cottonwood has taken away this possibility by hard-wiring safeguards:

1. If one VRU goes down the other comes on automatically
2. If neither VRU is operable the TEG circulation pumps shut down

I observed a test of this system. The operator shut down both VRUs and the circulation pumps shut down. PCV- 102B, set to open to atmosphere at 4 psig in the event of overpressure, stayed closed during this test and the rest of the visit. This regulator is on the inlet to the BTEX removal unit. It reacts to a rise in suction pressure above 4 psig.

Also hardwired is the regenerator's high pressure shutdown. If pressure reaches 80 in. w.c. (2.89 psig) not only does the burner shut down, the TEG circulation pumps also shut down, regardless of VRU status. I observed a successful test of this shutdown. The above regulator stayed closed.

Vapor Recovery Units
Hydrocarbon from the flash tank flows through V-144. Vapor disengages from the liquid and flows to the first VRU compressor. This unit compresses the gas from approx. 20 psig to 70 – 90 psig, depending on whether the vapor is returned to fuel gas or to gathering. Discharge gas is well over 100 deg. F. It flows through exchanger coils in the bottom of this vessel, heating liquid and keeping the VRU suction pressured with vapor. (A safeguard also exists, in which a low pressure suction triggers fuel gas flow that ensures a mimimum pressure for steady VRU operation.)

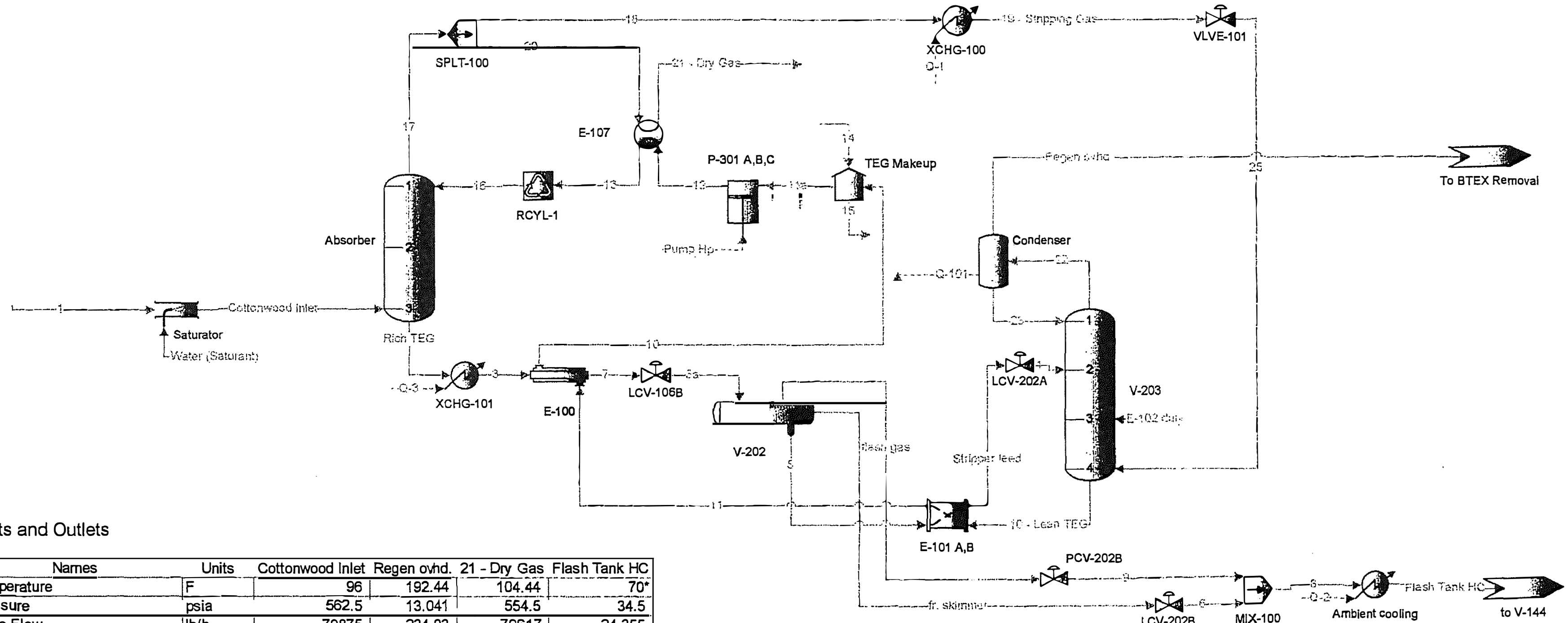
Any liquid trapped in the standpipe, used as a suction scrubber, flows to the low pressure (5-8 in. w.c.) vessel, V-140. Vapor from this overhead flows through two stages of VRU compression, each providing heat through vessel exchanger coils that keep vapor flowing to the units.

Liquids (water and hydrocarbon) commingle as shown, and go to the atmospheric tanks to be sold as condensate. Total liquid recovery from the BTEX and VRU sections is 14 bpd, or approximately 15 gal/mmscfd. This liquid has a 17 TVP and a 4 RVP.

The result of this design and operation is that Cottonwood dehydration is a zero-emission facility.

S L Huzyk

Sandra L. Huzyk, P. E.



Inlets and Outlets

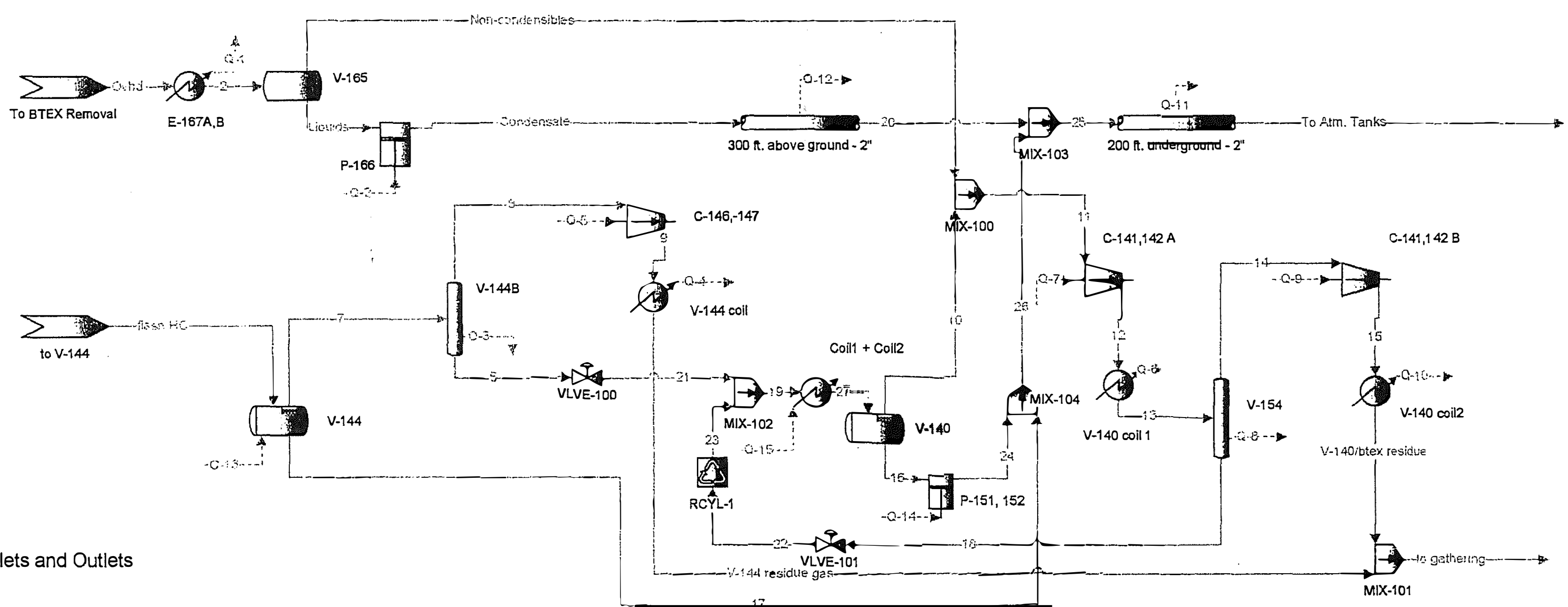
Names	Units	Cottonwood Inlet	Regen ovhd.	21 - Dry Gas	Flash Tank HC
Temperature	F	96	192.44	104.44	70*
Pressure	psia	562.5	13.041	554.5	34.5
Mass Flow	lb/h	79875	234.03	79617	24.355
Std Vapor Volumetric Flow	MMSCFD	40.069	0.08731	39.973	0.0087005
Propane(Mass Flow)	lb/h	3351.8	2.4552	3346.7	2.6228
i-Butane(Mass Flow)	lb/h	921.52	0.87184	919.83	0.82008
n-Butane(Mass Flow)	lb/h	1135.2	1.7177	1132.2	1.286
i-Pentane(Mass Flow)	lb/h	558.96	1.3318	556.91	0.72664
2,2-Dimethylbutane(Mass Flow)	lb/h	23.844	0.098547	23.709	0.036367
2,3-Dimethylbutane(Mass Flow)	lb/h	54.122	0.32725	53.703	0.09196
n-Pentane(Mass Flow)	lb/h	432.53	1.4676	430.41	0.65236
2-Methylpentane(Mass Flow)	lb/h	152.53	7.8451	144.29	0.3868
3-Methylpentane(Mass Flow)	lb/h	87.807	5.9372	81.638	0.23122
n-Hexane(Mass Flow)	lb/h	206.65	1.5648	204.71	0.36918
Cyclohexane(Mass Flow)	lb/h	103.86	5.0541	98.565	0.24504
Methylcyclohexane(Mass Flow)	lb/h	147.05	6.8805	139.84	0.32566
n-Heptane(Mass Flow)	lb/h	270.65	4.5566	265.55	0.54755
Octane(Mass Flow)	lb/h	80.27	2.9857	77.11	0.17409
Nonane(Mass Flow)	lb/h	38.867	3.7583	35.018	0.09053
Decane(Mass Flow)	lb/h	1.8747	0.42383	1.4463	0.0045447
Benzene(Mass Flow)	lb/h	40.481	7.5625	32.786	0.1326
Toluene(Mass Flow)	lb/h	46.132	14.488	31.486	0.15664
Water(Mass Flow)	lb/h	137.13	130.08	6.8686	0.19108

Liquid Circulation

Names	Units	10 - Lean TEG	Stripper feed	Rich TEG	fr. skimmer
Temperature	F	361.76	280*	98.565	
Pressure	psia	14	49	562.5	54
Mass Flow	lb/h	5078.7	5286.9	5311.3	0
Propane(Mass Flow)	lb/h	0.025281	1.3954	4.0182	0
i-Butane(Mass Flow)	lb/h	0.0085074	0.58213	1.4022	0
n-Butane(Mass Flow)	lb/h	0.013082	1.3637	2.6498	0
i-Pentane(Mass Flow)	lb/h	0.0083327	1.1595	1.8862	0
Benzene(Mass Flow)	lb/h	0.048683	7.6005	7.7331	0
Toluene(Mass Flow)	lb/h	0.18787	14.666	14.822	0
o-Xylene(Mass Flow)	lb/h	0.35912	8.4225	8.4638	0
Ethylbenzene(Mass Flow)	lb/h	0.014105	0.63224	0.63652	0
Std Liquid Volumetric Flow	sgpm	8.9996	9.4718	9.5939	0

Cottonwood Plant
Dehydration

May, 2006 Operation

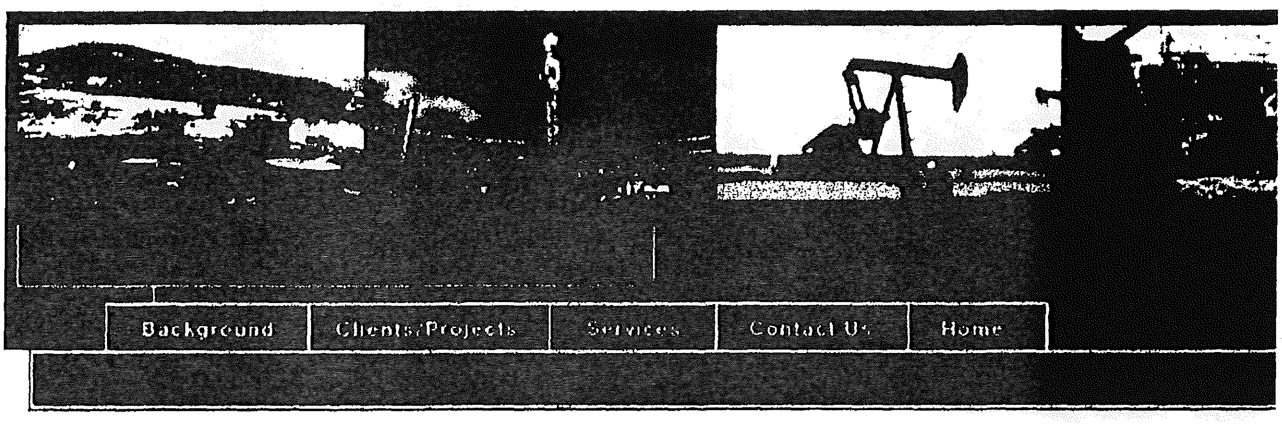


Inlets and Outlets

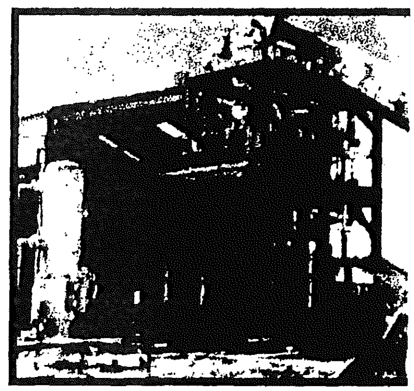
Names	Units	Ovhd.	flash HC	To Atm. Tanks	to gathering
Temperature	F	192.44	70	61.354	133.98
Pressure	psia	13.041	34.5	17.497	82
Mass Flow	lb/h	234.03	24.355	192.38	66.001
Std Vapor Volumetric Flow	MMSCFD	0.08731	0.0087005	0.071672	0.024339
Std Liquid Volumetric Flow	bbl/d	21.684	4.1864	14.457	11.413
Propane(Mass Flow)	lb/h	2.4552	2.6228	0.13102	4.947
i-Butane(Mass Flow)	lb/h	0.87184	0.82008	0.11973	1.5722
n-Butane(Mass Flow)	lb/h	1.7177	1.286	0.3324	2.6714
i-Pentane(Mass Flow)	lb/h	1.3318	0.72664	0.53343	1.525
2,2-Dimethylbutane(Mass Flow)	lb/h	0.098547	0.036367	0.061005	0.073909
2,3-Dimethylbutane(Mass Flow)	lb/h	0.32725	0.09196	0.23093	0.18827
n-Pentane(Mass Flow)	lb/h	1.4676	0.65236	0.71254	1.4074
2-Methylpentane(Mass Flow)	lb/h	7.8451	0.3868	5.055	3.1769
3-Methylpentane(Mass Flow)	lb/h	5.9372	0.23122	4.0067	2.1617
n-Hexane(Mass Flow)	lb/h	1.5648	0.36918	1.2849	0.64903
Cyclohexane(Mass Flow)	lb/h	5.0541	0.24504	4.0186	1.2805
Methylcyclohexane(Mass Flow)	lb/h	6.8805	0.32566	6.4372	0.76898
n-Heptane(Mass Flow)	lb/h	4.5566	0.54755	4.4904	0.61372
Octane(Mass Flow)	lb/h	2.9857	0.17409	3.0479	0.11195
Nonane(Mass Flow)	lb/h	3.7583	0.09053	3.8129	0.035988
Decane(Mass Flow)	lb/h	0.42383	0.0045447	0.42723	0.001154
Benzene(Mass Flow)	lb/h	7.5625	0.1326	5.8222	1.8729
Toluene(Mass Flow)	lb/h	14.488	0.15664	13.583	1.0612
o-Xylene(Mass Flow)	lb/h	8.0651	0.041251	7.9831	0.12332
Ethylbenzene(Mass Flow)	lb/h	0.61838	0.0042878	0.60753	0.015143
Water(Mass Flow)	lb/h	130.08	0.19108	129.61	0.66518

Cottonwood Plant
BTEX Removal and Vapor Recovery

May, 2006 Operation



Sandra L. Huzyk, P. E. began Huzyk Energy Management, Inc. in 1993 as a consulting engineering and process safety management company to help oil and gas companies manage production and processing for profit and safety. Just past its 11th anniversary, HEM has evolved into chemical engineering consulting, design and project management for energy, chemical, research and other industries.



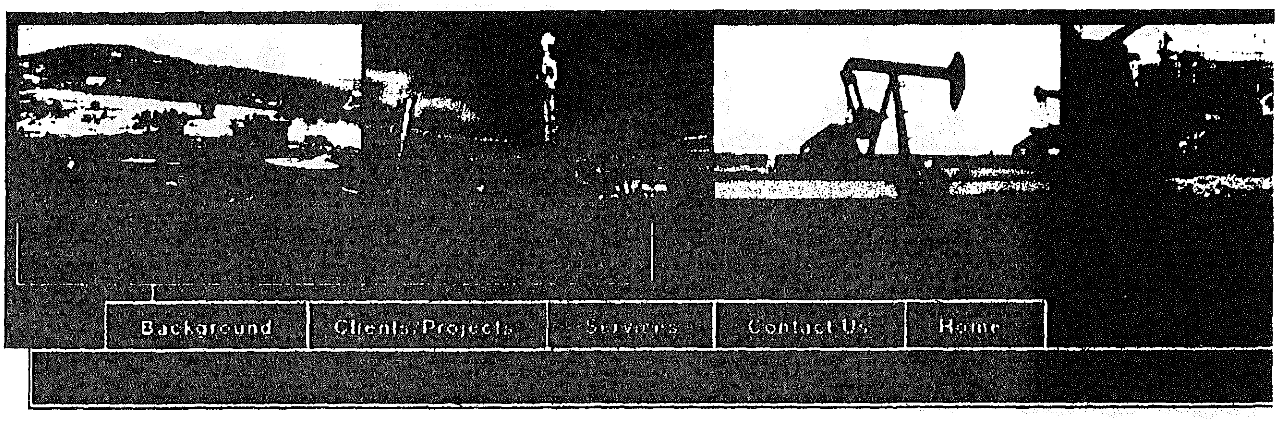
Direct Oxidation Pilot Plar

Sandra has been a chemical engineer for 26 years. She was a process engineer for Amoco Production Company for 11 years and project manager for an engineering company for 3 years. Most of this time was spent in the design, construction, startup and optimization of refrigeration, expander, cryogenic and fractionation plants; such as the 50 MMSCFD A.R.E. East Lobe expander plant, the 400 MMSCFD Anschutz NGL/NRU and the 250 MMSCFD Painter NGL/NRU.

She began her treating and sulfur recovery design/operating experience in 1982 on the 275 MM (1100 ltd) Whitney Canyon plant and the ULTRA pilot plant. She has continued hydrocarbon rec dehydration, sweetening, sulfur recovery and tailgas cleanup projects since then.

Sandra has a BS in Chemistry from the University of Colorado (Colorado Springs; 1976) and an Chemical and Petroleum Refining Engineering from Colorado School of Mines; 1980.

Publication:
"Anschutz Ranch East Facilities Development";
June 13, 1998, <u>Oil and Gas Journal.</u>



A Short Client List with typical Process Design, Project Management and Consulting Prc

Forest Oil
Feasibility Study, Design and skid-mounting 20 mmscfd selexol
a) Project Management: Plant on 56% CO_2
b) Allocation audit on 40 MMSCFD Uintah Basin plant

BP-Amoco Oil
a) Provided preliminary engineering, PFDs and installed project cost/economics for the upgrade of a 52,000 bpd BP fractionation complex to 85,000 bpd; as well as for the addition of a CO2 removal unit and a butane splitter.
b) Increased the capacity of the Painter Fractionation Facility from 7500 bpd to 9400 bpd for ¼ of the proposed budget, and assisted in PSM management of change tasks.

TDA Reasearch, Inc.
Provided bid packages, project engineering and project management for the completed design and installation of a direct-oxidation sulfur recovery pilot plant to test client's patented catalyst. Provided assistance with startup and operation, until turned over for day-to-day operation. HEM also found and negotiated rights to the host site.

Direct-oxidation SRU technology licensed by SulfaTreat, 2004.

Encana Gathering Services
Provided preliminary engineering and several after-tax economic scenarios for construction of 250 MMSCFD refrigeration and expander plants

Bear Paw Energy
HEM acted as Engineering Manager for the startup company, hiring employees, setting up PSM program and building the following projects:
a) refurbished and installed a used, 20 gpm amine plant at Baker, MT
b) installed a satellite compressor station, outside Baker, MT
c) installed deisobutanizer in fractionation plant outside Sidney, MT
d) 2005 capacity study for stablilization, compression, expander, and fractionation trains of 60 MMSCFD Grasslands plant.

Laramie Energy
Design and installation of two dewpoint control plants (compression, CO_2 removal, dehydration, J-T skid) in the Piceance Basin.

Radian International, LLC
Collaboration on tailgas treating study to spec equipment and determine operating costs. Results compiled in the paper, "H2S Removal and Sulfur Recovery Options for High Pressure Natural Gas with Medium Amounts of Sulfur". Presented by Radian (Crystasulf) engineers Nov. 1, 2000 at the Sulfur 2000 International Conference in San Francisco.

Duke Energy Field Services
Successfully completed consulting assignment to increase the throughput of a 35 MMSCFD expander plant to 47 MMSCFD. Also detailed a solution approved by plant and management to avoid the installation of a TEG dehydration plant, while increasing condensate production by 50 bpd.

Smith, Claudia

From: Smith, Claudia
Sent: Thursday, December 08, 2016 4:55 PM
Subject: Notice of Public Comment Period – Proposed Permit to Construct on the Uintah and Ouray Indian Reservation
Attachments: Bulletin Board Notice - Anadarko Cottonwood Wash CS SMNSR.pdf

In accordance with the regulations at 40 CFR 49.157 and 49.158, the EPA is hereby providing notification of the availability for public comment of the proposed Clean Air Act synthetic minor New Source Review permit for the following source located on Indian country lands within the Uintah and Ouray Indian Reservation:

Anadarko Uintah Midstream, LLC – Cottonwood Wash Compressor Station

Electronic copies of the proposed permit, technical support document, application and other supporting permit information may be viewed online at http://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8.

Paper copies of the proposed permit, technical support document, application, and other supporting permit information may be reviewed by contacting the Federal and/or Tribal contacts identified on the attached public notice bulletin.

Comments may be sent by mail to:

US EPA Region 8
Air Program Office
1595 Wynkoop Street, 8P-AR
Denver, CO 80202
Attn: Tribal NSR Coordinator

or

Electronically to R8AirPermitting@epa.gov

In accordance with the regulations at §49.157, the Agency is providing a 30-day period from December 9, 2016, to January 9, 2017, for public comment on this proposed permit. Comments must be received by 5:00pm MT January 9, 2017, to be considered in the issuance of the final permit. If a public hearing is held regarding this permit, you will be sent a copy of the public hearing notice at least 30 days in advance of the hearing date.

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
****

Smith, Claudia

From:	Smith, Claudia
Sent:	Thursday, December 08, 2016 4:54 PM
To:	mike.weaver@anadarko.com
Cc:	Minnie Grant; Bruce Pargeets; Fallon, Gail; Schlichtemeier, Chad; Ohlhausen, Natalie
Subject:	Proposed Synthetic Minor NSR Permit for Cottonwood Wash Compressor Station
Attachments:	AnadarkoCottonwoodWash_ProposedPermit_SMNSR-UO-000007-2012 001.pdf; Bulletin Board Notice - Anadarko Cottonwood Wash CS SMNSR.pdf

I have attached the requested proposed permit, the accompanying technical support document, and the bulletin board notice for the Cottonwood Wash Compressor Station. We will also be posting the proposed permit, technical support document, application and other supporting permit information in PDF format on our website at http://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8 by the start of the public comment period.

In accordance with the regulations at 40 CFR 49.157 and 49.158, we are providing a 30-day period from December 9, 2016 to January 9, 2017 for public comment on this proposed permit. Comments must be received by 5:00pm MT January 9, 2017, to be considered in the issuance of the final permit.

Please submit any written comments you may have concerning the terms and conditions of this permit. You can send them directly to me at smith.claudia@epa.gov, or to r8airpermitting@epa.gov. Should the EPA not accept any or all of these comments, you will be notified in writing and will be provided with the reasons for not accepting them.

Thank you,

Claudia Young Smith
Environmental Scientist
Air Program, Mail Code 8P-AR
US Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, Colorado 80202

Phone: (303) 312-6520
Fax: (303) 312-6064
http://www.epa.gov/caa-permitting/caa-permitting-epas-mountains-and-plains-region
****

Public Notice: Request For Comments

Proposed Air Quality Permit to Construct
Anadarko Uintah Midstream, LLC
Cottonwood Wash Compressor Station

Notice issued: December 9, 2016

Written comments due:
5 p.m., January 9, 2017

Where is the facility located?

Cottonwood Wash Compressor Station:
Uintah and Ouray Indian Reservation
Uintah County, Utah
Sec. 27, T9S, R21E
Latitude 40.009722 N
Longitude -109.543889 W

What is being proposed?

This permit action will apply to an existing facility operating on the Uintah and Ouray Indian Reservation in Utah.

The Cottonwood Wash Compressor Station is a natural gas production facility used for natural gas compression and treatment of natural gas from the field.

Anadarko Uintah Midstream, LLC currently operates under a Federal Consent Decree (CD) between the United States of America (Plaintiff) and the State of Colorado, the Rocky Mountain Clean Air Action and the Natural Resources Defense Council (Plaintiff-Intervenors), and Kerr-McGee Corporation (Civil Action No. 07-CV-0134-EWN-KMT).

The facility currently operates nine (9) natural gas-fired 4-stroke lean-burn (4SLB) reciprocating internal combustion engines to compress pipeline natural gas from the field, one low-emission tri-ethylene glycol (TEG) dehydration system, three (3) 400-barrel natural gas condensate and produced water storage tanks.

Anadarko has requested enforceable requirements for the installation and operation of the low-emission TEG dehydration system for control of volatile organic compound emissions. Anadarko has also requested enforceable restrictions on carbon monoxide (CO) emissions for the 4SLB compressor engines using catalytic emissions control systems. Anadarko also requested enforceable requirements for installation and operation of a flare to control VOC emissions from the natural gas condensate and produced water storage tanks. Lastly, Anadarko requested enforceable requirements to install and operate only instrument air-driven pneumatic controllers. The permit the EPA is proposing to issue reflects the incorporation of the requested requirements, which are based on the Federal CD.

What are the effects on air quality?
This action will have no adverse air quality impacts. The emissions at this existing facility will not be increasing due to this permit action. In addition, this action does not authorize the construction of any new emission sources, or emission increases from existing sources, nor does it otherwise authorize any other physical modifications to the facility or its operations.

Where can I send comments?
EPA accepts comments by mail, fax and e-mail.

US EPA Region 8 Air Program, 8P-AR
Attn: Federal Minor NSR Coordinator
1595 Wynkoop Street,
Denver, CO 80202
R8AirPermitting@epa.gov
Fax: 303-312-6064

How can I review documents?
You can review a paper or electronic copy of the proposed permit and related documents at the following locations:

Ute Indian Tribe Energy and Minerals Department Office
988 South 7500 East, Annex Building
Fort Duchesne, Utah 84026
Contact: Minnie Grant, Air Coordinator, at (435) 725-4900
or minnieg@utetribe.com

US EPA Region 8 Office:
1595 Wynkoop Street, Denver, CO 80202
Hours: Mon-Fri 8:00 a.m. – 5:00 p.m.
Contact: Claudia Smith, Environmental Scientist, at 303-312-6520
or smith.claudia@epa.gov

US EPA Region 8 Website:
https://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8

Permit number:
SMNSR-UO-000007-2012.001

What happens next?
The EPA will review and consider all comments received during the comment period. Following this review, the EPA may issue the permits as proposed, issue modified permits based on comments, or deny the permits.

Tribal Minor New Source Review in Indian Country

United States Environmental Protection Agency

Region 8
Air Program
1595 Wynkoop Street
Denver, CO 80202
Phone 800-227-8917

https://www.epa.gov/caa-permitting/tribal-nsr-permits-region-8

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

Ref: 8P-AR

DEC - 5 2016

Mike Weaver
Midstream Operations Manager
Anadarko Uintah Midstream, LLC
P.O. Box 173779
Denver, Colorado 80202-3779

Re: Anadarko Uintah Midstream, LLC, Cottonwood Wash Compressor Station, Permit # SMNSR-UO-000007-2012.001, Proposed Synthetic Minor New Source Review Permit

Dear Mr. Weaver:

The U.S. Environmental Protection Agency Region 8 has completed its review of Anadarko Uintah Midstream, LLC's application requesting a synthetic minor permit pursuant to the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49 for the Cottonwood Wash Compressor Station.

Enclosed are the proposed permit and the corresponding technical support document. The regulations at 40 CFR 49.157 require that the affected community and the general public have the opportunity to submit written comments on any proposed MNSR permit. All written comments submitted within 30 calendar days after the public notice is published will be considered by the EPA in making its final permit decision. Enclosed is a copy of the public notice which will be published on the EPA's website located at: https://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8, on December 9, 2016. The public comment period will end at 5:00 p.m. on January 9, 2017.

The conditions contained in the proposed permit will become effective and enforceable by the EPA if the permit is issued final. If you are unable to accept any term or condition of the draft permit, please submit your written comments, along with the reason(s) for non-acceptance to:

Tribal NSR Permit Contact
c/o Air Program (8P-AR)
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, Colorado 80202

or

R8AirPermitting@epa.gov

If you have any questions concerning the enclosed proposed permit or technical support document, please contact Claudia Smith of my staff at (303) 312-6520.

Sincerely,

Carl Daly

Carl Daly
Director
Air Program

Enclosures (2)

cc: Bruce Pargeets, Director, Energy, Minerals and Air, Ute Indian Tribe
Minnie Grant, Air Coordinator, Energy, Minerals, and Air, Ute Indian Tribe
Honorable Shaun Chapoose, Chairman, Ute Indian Business Committee (w/o enclosures)
Edred Secakuku, Vice Chairman, Ute Indian Business Committee (w/o enclosures)
Reannin Tapoof, Executive Assistant, Ute Indian Business Committee (w/o enclosures)

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-UO-000007-2012.001

Permit to Construct to establish legally and practically enforceable limitations and requirements on sources at an existing facility.

Permittee:

Anadarko Uintah Midstream, LLC

Permitted Facility:

Cottonwood Wash Compressor Station
Uintah and Ouray Indian Reservation
Uintah County, Utah

Summary

On August 30, 2012, we received an application from Anadarko Uintah Midstream, LLC (Anadarko) requesting a synthetic minor permit for the Cottonwood Wash Compressor Station in accordance with the requirements of the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR part 49. We received a new application replacing the original application on September 20, 2013, with additional supplementary information on August 28, 2014, and July 21, 2015.

This proposed permit action applies to an existing facility operating on Indian country lands within the Uintah and Ouray Indian Reservation in Utah.

This permit does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is only intended to incorporate required and requested enforceable emission limits and operational restrictions from a March 27, 2008, Federal Consent Decree between the United States of America (Plaintiff), and the State of Colorado, the Rocky Mountain Clean Air Action and the Natural Resources Defense Council (Plaintiff-Intervenors), and Kerr-McGee Corporation (Civil Action No. 07-CV-01034-EWN-KMT), and the September 20, 2013 synthetic minor MNSR application and supplementary submittals (see 40 CFR 49.151(c)(1)(ii)(d)) and 49.158(c)(4)(ii) and (iii)). Anadarko has requested legally and practically enforceable requirements for the installation and operation of a low-emission tri-ethylene glycol (TEG) dehydration system for control of volatile organic compound (VOC) emissions. Anadarko also requested enforceable requirements for installation and operation of a flare to control VOC emissions from natural gas condensate and produced water storage tanks at the facility, including an associated average daily production limit for natural gas condensate and produced water processed through the tanks. Additionally, Anadarko requested enforceable requirements for installation and operation of a catalytic control system on each of nine (9) natural gas-fired 4-stroke lean-burn (4SLB) reciprocating internal combustion engines used for natural gas compression at the facility, including associated carbon monoxide (CO) emission limits. Lastly, Anadarko requested an enforceable requirement to install and operate only instrument air-driven pneumatic controllers.

Upon compliance with the permit, Anadarko will have legally and practically enforceable restrictions on emissions that can be used when determining the applicability of other Clean Air Act (CAA) permitting requirements, such as under the Prevention of Significant Deterioration (PSD) Permit Program at 40 CFR part 52 and the Title V Operating Permit Program at 40 CFR part 71 (part 71).

The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

Table of Contents

I. Conditional Permit to Construct

A. General Information

Facility: Anadarko Uintah Midstream, LLC – Cottonwood Wash Compressor Station

Permit number: SMNSR-UO-000007-2012.001

SIC Code and SIC Description: 1311- Crude Petroleum and Natural Gas

Site Location:
Cottonwood Wash Compressor Station
Sec 27 T9S R21E
Uintah and Ouray Indian Reservation
Uintah County, Utah
Latitude 40.009722, Longitude -109.543889

Corporate Office Location
Anadarko Uintah Midstream, LLC
P.O. Box 173779
Denver, Colorado 80202-3779

The equipment listed in this permit shall be operated by Anadarko Uintah Midstream, LLC at the location described above.

B. Applicability

1. This federal Permit to Construct is being issued under authority of the MNSR Permit Program.

2. The requirements in this permit have been created, at the Permittee's request and pursuant to the MNSR permit program to establish legally and practically enforceable emissions restrictions, initially established through a Consent Decree (Civil Action No. 07-CV-01034-EWN-KMT) for control of VOC TEG dehydration system, produced water storage tank and pneumatic controller emissions, and CO engine emissions.

3. Any conditions established for this facility or any specific units at this facility pursuant to any permit issued under the authority of the PSD Permit Program or the MNSR Permit Program shall continue to apply.

4. By issuing this permit, 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.

C. Requirements for the Low-Emission Dehydrator

1. Construction and Operational Limits

   (a) The Permittee shall install, operate, and maintain no more than one (1) TEG Low-Emission Dehydrator meeting the following specifications:

      (i) Limited to a maximum throughput of 85 million standard cubic feet per day (MMscfd) of natural gas;

      (ii) Certified as a "Low-Emission Dehydrator" that:

(A) Incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function;

(B) Either returns the captured vapors to the inlet of the facility where the dehydrator is located or routes the captured vapors to the facility's fuel gas supply header; and

(C) Meets the control and operational requirements specified in this permit.

(b) Only the dehydration unit that is operated and controlled as specified in this permit is approved for installation and operation under this permit.

2. Emission Limits:

(a) Emissions from the Low-Emission Dehydrator shall not exceed 1.0 tons of VOC in any consecutive 12-month period.

(b) Emission limits shall apply at all times, unless otherwise specified in this permit.

3. Emissions Calculation Requirements

(a) VOC emissions for the Low Emission Dehydrator shall be calculated, in tons, and recorded at the end of each month, beginning with the first calendar month that this permit is effective.

(b) Prior to 12 full months of VOC emissions calculations, the Permittee must, within 7 calendars days of the end of each month, add the emissions for that month to the calculated emissions for all previous months since production commenced and record the total. Thereafter, the Permittee must, within seven 7 calendars days of the end of each month, add the emissions for that month to the calculated emissions for the preceding 11 months and record a new 12-month total.

(c) VOC emissions shall be calculated, in tons, using a generally accepted simulation model or software (examples include ProMax and GRI-GLYCalc™ Version 4.0 or higher). Inputs to the model shall be representative of actual average monthly operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1).

4. Control and Operational Requirements

(a) The Permittee shall route all non-condensable emissions from the Low Emission Dehydrator process vent and flash tank through a closed-vent system to a vapor recovery unit (VRU) with reciprocating or scroll compressors.

(b) The Low Emission Dehydrator and VRU system shall have at least three (3) levels of protection to prevent VOC emissions from occurring:

(i) Physical electrical hard-wiring between the VRU compressor(s) and the TEG circulation pump employed to ensure that if the VRU ceases to operate, the TEG pump also shuts down, thereby halting the circulation of TEG through the wet gas and preventing emissions associated with the regeneration of the TEG;

(ii) A second level of protection (redundancy) is incorporated into a Programmable Logic Controller that uses instrumentation to shut down the Low Emission Dehydrator in the event the VRU compressor ceases to operate; and

(iii) A third level of protection pumps the non-condensable gases from the Low Emission Dehydrator exclusively to the station inlet or fuel system for use as fuel and ensures it is not used for blanket gas in storage tanks or otherwise vented to the atmosphere.

5. Monitoring Requirements

(a) The Permittee shall inspect the Low Emission Dehydrator and VRU on a daily basis to ensure proper operation according to the manufacturer's maintenance recommendations.

(b) The Permittee shall monitor the closed-vent system for leaks of hydrocarbon emissions from all vent lines, connections, fittings, valves, relief valves, or any other appurtenance employed to contain, collect, and transport gases, vapors, and fumes to the VRU as follows:

(i) Visit the facility on a quarterly basis to inspect the closed-vent system for defects that could result in air emissions and document each inspection. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. If a quarterly visit is not feasible due to sudden, infrequent, and unavoidable events (e.g. weather, road conditions), every effort shall be made to visit the facility as close to quarterly as possible;

(ii) The inspections shall be based on audio, visual, and olfactory procedures; and

(iii) Any leaks detected in the closed-vent system shall be addressed immediately unless the repair requires resources not currently available. If the resources are not available, the leak shall be repaired no later than 15 days after initial detection of the leak.

(c) The Permittee shall install operate, and maintain a meter that continuously measures the natural gas flowrate to the Low Emission Dehydrator with an accuracy of plus or minus 2% or better. The meter shall be inspected on a monthly basis to ensure proper operation per the manufacturer's specifications.

(d) The Permittee shall convert monthly natural gas flowrate to a daily average by dividing the monthly flowrate by the number of days in the month that the Low Emission Dehydrator processed natural gas. The Permittee shall document the actual monthly average natural gas flowrate.

6. Recordkeeping Requirements

(a) The Permittee shall document compliance with the VOC emission limits in this permit by keeping the following records:

(i) All manufacturer and/or vendor specifications for the Low Emission Dehydrator, VRU, closed-vent system, and any monitoring equipment, adequate to demonstrate its compliance with the requirements of this permit;
(ii) All extended wet gas analyses;
(iii) The actual monthly average natural gas flow rate; and
(iv) The total monthly and consecutive 12-month VOC emissions calculations for the Low Emission Dehydrator.

D. Requirements for 4SLB Compressor Engines

1. Construction and Operational Requirements

(a) The Permittee shall install and operate emission controls as specified in this permit on nine (9) existing engines used for natural gas compression, all meeting the following specifications:

(i) Operated as a 4-stroke lean-burn engine;
(ii) Fired with natural gas; and
(iii) Four (4) engines limited to a maximum site rating of 1,340 horsepower (hp), two (2) engines limited to a maximum site rating of 1,775 hp and five (5) engines limited to a maximum site rating of 2,370 hp.

(b) Only the engines that are operated and controlled as specified in this permit are approved for installation under this permit.

2. Emission Limits:

(a) CO emissions from each 1,340 hp compressor engine shall not exceed 1.21 grams per hp-hour (g/hp-hr).

(b) CO emissions from each 1,775 hp or 2,370 hp compressor engine shall not exceed 1.63 g/hp-hr.

(c) Emission limits shall apply at all times, unless otherwise specified in this permit.

3. Control and Operational Requirements

(a) The Permittee shall install, continuously operate and maintain a catalytic control system on each engine that is capable of reducing the uncontrolled emissions of CO to meet the emission limits specified in this permit.

(b) The Permittee shall install, continuously operate and maintain temperature-sensing devices (i.e. thermocouple or resistance temperature detectors) before the catalytic control system on each engine 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 specifications or equivalent specifications developed by the Permittee or vendor.

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

(d) 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 reading taken during the initial performance test. The baseline pressure drop across the catalyst bed shall be determined at 100% ±10% of the engine load measured during the most recent performance test or portable analyzer monitoring event, as specified in this permit.

(e) The Permittee shall fire each engine with natural gas only. The natural gas shall be pipeline-quality in all respects except that the CO_2 concentration in the gas is not required to be within pipeline-quality.

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

(g) The Permittee may rebuild an existing permitted engine or replace an existing permitted engine with an engine of the same hp 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 engines that are rebuilt or replaced shall also apply to the replaced engines.

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

4. <u>Performance Test Requirements</u>

(a) Performance tests shall be conducted on each engine for measuring CO to demonstrate compliance with the emission limits in this permit. The performance tests shall be conducted in accordance with appropriate reference methods specified in 40 CFR part 60, Appendix A, and/or an EPA-approved American Society for Testing and Materials (ASTM) method.

(i) The initial performance tests shall be conducted within 90 calendar days after the effective date of this permit. The results of performance tests conducted prior to the effective date of this permit may be used to demonstrate compliance with the initial performance test requirements, provided the tests were conducted in an equivalent manner as the performance test requirements in this permit.

(ii) Subsequent performance tests shall be conducted on each engine within 6 months of most recent performance test. After compliance is demonstrated for two consecutive tests, the testing frequency shall be reduced to annually if the facility-wide CO emissions are less than 150 tons per year (tpy). Facility-wide CO emissions shall be calculated based on the results of the most recent test and assuming 8,760 hours of operation per year. If the total facility-wide CO emissions exceed 150 tpy, then the Permittee shall resume semi-annual testing.

(iii) Performance tests shall be conducted within 90 calendar days of the replacement of the catalyst on each engine.

(iv) Performance tests shall be conducted within 90 calendar days of startup of all rebuilt and replacement engines.

(b) The Permittee may submit to the EPA a written request for approval of alternate test methods, but shall only use the alternate test methods after obtaining written approval from the EPA.

(c) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, processes or operational parameters immediately prior to the engine testing or during the engine testing. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. Artificially increasing an engine load to meet testing requirements is not considered engine tuning or adjustments.

(d) The Permittee shall not abort any engine tests that demonstrate non-compliance with the CO emission limits.

(e) All performance tests conducted on the engines 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 per test.

(ii) The Permittee shall measure oxygen (O_2), CO and nitrogen oxides (NO_X) emissions in g/hp-hr at the outlet of the control device using a portable analyzer in accordance with EPA Reference Method 10 at 40 CFR part 60, Appendix A, or ASTM method D6522-00 (2005). Measurements to determine O_2 and NO_X shall be made simultaneously with measurements for CO concentration. *[Note to Permittee: Although the permit does not contain NO_X emission limits for the engines, NO_X measurement requirements have been included as an indicator to ensure compliance with Condition D.4(c) above.]*

(iii) The Permittee shall convert g/hp-hr measurements using EPA Reference Method 19 at 40 CFR part 60, Appendix A, and the manufacturer's specific fuel consumption or measured fuel consumption and horsepower at the time of testing.

(iv) All performance tests shall be conducted at maximum operating rate (90% to 110% of the maximum achievable load available at the time 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 written approval from the EPA.

(v) 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.).

(vi) 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.

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

(viii) 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.

(ix) 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).

(f) 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 if the testing cannot be performed.

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

5. <u>Monitoring Requirements</u>

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

(b) Except during startups, which shall not exceed 30 minutes, if the engine exhaust temperature at the inlet to the catalyst bed on any engine deviates from the acceptable range 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 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's 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 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 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 each 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 performed on that day, or an average of all the measurements on that day if continuous readings are taken.

(e) If the pressure drop exceeds ± 2 inches of water from the baseline pressure drop reading taken during the most recent performance test, 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, 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 can be corrected by following the catalytic control system manufacturer's 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 cannot be corrected using the catalytic control system manufacturer's 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 emission limits are being met and to re-establish the pressure drop across the catalyst bed. The Permittee shall perform a portable analyzer test to 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. Corrective action may include removal and cleaning of the catalyst or replacement of the catalyst.

(f) The Permittee is not required to conduct parametric monitoring of exhaust temperature and catalyst differential pressure on an engine if it has not operated during the monitoring period. The Permittee shall certify that the engine did not operate during the monitoring period in the annual report specified in this permit.

6. Recordkeeping Requirements

(a) Records shall be kept of manufacturer and/or vendor specifications for each engine, catalytic control system, temperature-sensing device and pressure-measuring device.

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

(c) Records shall be kept that are sufficient to demonstrate that the fuel for each engine is pipeline quality natural gas in all respects, with the exception of CO_2 concentrations.

(d) 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.

(e) 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.

(f) Records shall be kept of all required testing 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.

(g) Records shall be kept of all catalyst replacements, engine rebuilds and engine replacements.

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

(i) Records shall be kept of each time an engine is shut down due to a deviation in the inlet temperature to the catalyst bed or pressure drop across a 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.

E. Requirements for Storage Tanks

1. Construction, Control and Operational Requirements

(a) The Permittee shall install, operate, and maintain no more than three (3) tanks used to store natural gas condensate and produced water, each limited to a maximum storage capacity of 400 barrels (bbl);

(b) The Permittee shall, at a minimum, route all natural gas condensate and produced water storage tank emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare designed and operated as specified in this permit.

(c) Only the storage tanks that are operated and controlled as specified in this permit are approved for installation under this permit.

2. Production Limit: The total condensate and produced water processed through the storage tanks shall not exceed 13 barrels per day on average.

3. Closed-Vent Systems

(a) The Permittee shall design, install, continuously operate and maintain each closed-vent system such that it is compliant with the following requirements:

(i) The closed-vent system shall route all gases, vapors, and fumes emitted from the natural gas condensate and produced water storage tanks to the flare;

(ii) All vent lines, connections, fittings, valves, relief valves or any other appurtenance employed to contain and collect gases, vapors, and fumes and transport them to the flare shall be maintained and operated during any time the device is operating;

(iii) The closed-vent system shall be designed to operate with no detectable emissions;

(iv) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the flare, the Permittee shall meet the one of following requirements for each bypass device:

(A) At the inlet to the bypass device that could divert the stream away from the flare and into the atmosphere, properly install, calibrate, maintain and operate a flow indicator that is capable of taking periodic readings and sounding an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the flare and into the atmosphere; or

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

(v) The Permittee shall minimize leaks of hydrocarbon emissions from all vent lines, connections, fittings, valves, relief valves or any other appurtenance employed to contain, collect, and transport gases, vapors, and fumes to the flare.

4. Flare

(a) The Permittee shall design, install, continuously operate and maintain a flare such that the mass content of the uncontrolled VOC emissions from the natural gas condensate and produced water storage tanks are reduced by at least 95.0 percent by weight.

(b) The Permittee shall ensure that the flare has sufficient capacity to achieve at least a 95.0 percent VOC emission control efficiency for the minimum and maximum hydrocarbon volumetric flow rate and BTU content routed to the device.

(c) The Permittee shall ensure that the flare is designed and operated in accordance with the requirements of 40 CFR 60.18(c) through (e).

(d) The Permittee shall ensure that the flare is:

(i) Operated properly at all times that natural gas condensate and produced water storage tank emissions are routed to it;

(ii) Equipped and operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the 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 pilot flame fails while natural gas condensate and produced water storage tank emissions are routed to it;

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

(vi) Operated with no visible smoke emissions.

(e) The Permittee shall follow the manufacturer's recommended maintenance schedule and operational procedures, or recommended maintenance schedule and operational procedures developed by the vendor or Permittee, to ensure optimum performance of the closed-vent systems and flare.

5. Testing and Monitoring Requirements

(a) The Permittee shall measure the barrels of natural gas condensate and produced water stored in the tanks each time the liquids are unloaded from the storage tanks using process flow meters and/or sales records. At the end of each calendar month, the total barrels of natural gas condensate and produced water stored in the tanks shall be divided by the number of days in that month to calculate a daily average.

(b) The Permittee shall perform weekly auditory, visual, olfactory (AVO) inspections of tank thief hatches, covers, seals, pressure relief valves and the closed vent system, to ensure proper condition and functioning. The weekly inspections shall be performed while the natural gas condensate and produced water storage tanks are being filled. If any of the components are not in good working condition, they must be repaired within 15 days of identification of the deficient condition.

(c) The Permittee shall perform monthly visual inspections of the peak pressure and vacuum values in each tank and the closed-vent system to ensure that the pressure and vacuum relief set points are not being exceeded in a way that has resulted, or might result, in venting of emissions and possible damage to equipment, and to ensure that the closed-vent system operates with no detectable emissions. Monthly visual inspections shall be conducted as follows:

(i) The monthly inspections shall be performed using an optical gas imaging instrument and while the natural gas condensate and produced water storage tanks are being filled;

(ii) If any detectable emissions or visible smoke emissions are detected using the optical gas imaging instrument, the Permittee shall take the following actions, as applicable:

(A) The Permittee shall demonstrate that the natural gas condensate and produced water storage tanks and the closed-vent system operate with no detectable emissions using the procedures specified in EPA Method 21 at 40 CFR part 60, Appendix A. A potential leak is determined to operate with no detectable emissions if the VOC concentration value measured by the Method 21 detection instrument is less than 500 parts per million volume (ppmv);

(B) If the closed-vent system or flare fail the detectable emissions or visual emissions test, the Permittee shall follow the manufacturer's, vendor's, or Permittee's repair instructions to return the emissions source to compliant operation. All repairs and maintenance activities shall be recorded in a maintenance and repair log and shall be made available for inspection;

(C) Upon return to operation from any repair and maintenance activity, the closed-vent system or flare shall pass a Method 21 or Method 22 test, as applicable;

(D) If the closed-vent system or flare fail a follow up Method 21 or Method 22 test, the Permittee shall repeat the procedures in paragraphs (A) through (C) of this section, as applicable, until the closed-vent system or flare passes a follow up test; and

(E) The Monthly VOC emissions calculations required in this permit shall account for the time periods between each failed detectable emissions or visible emissions test, as applicable, and subsequent compliant tests, assuming the emissions were uncontrolled.

(d) The Permittee shall monitor the operation of the flare to confirm proper operation and demonstrate compliance with the VOC control efficiency requirements of this permit as follows:

(i) Continuously monitor the flare operation, using a malfunction alarm and remote notification system for failures, and checking the system for proper operation whenever an operator is on site, at least weekly;

(ii) Continuously monitor all variable operational parameters specified in the manufacturer's written operating instructions and procedures;

(iii) Respond to any observation of improper monitoring equipment operation or any alarm of pilot flame failure and ensure that monitoring equipment is returned to proper operation and/or the pilot flame is relit as soon as practically and safely possible after an observation or an alarm sounds;

(iv) Perform monthly visual inspections of the flare to ensure it operates with no visible smoke emissions. Monthly visual inspections shall be conducted as follows:

(A) The monthly inspections shall be performed using an optical gas imaging instrument and while the natural gas condensate and produced water storage tanks are being filled;

(B) If any visible smoke emissions are detected using the optical gas imaging instrument, the Permittee shall take the following actions:

(I) The Permittee shall demonstrate that the flare operates with no visible emissions, except for periods not to exceed a total of 2 minutes during any hour, using the procedures specified in EPA Method 22 at 40 CFR part 60, Appendix A. The observation period shall be 1 hour;

(II) If the flare fails the visual emissions test, the Permittee shall follow the manufacturer's, vendor's, or Permittee's repair instructions to return the flare to compliant operation. All repairs and maintenance activities shall be recorded in a maintenance and repair log and shall be made available for inspection;

(III) Upon return to operation from any repair and maintenance activity, the flare shall pass a Method 22 test; and

(IV) If the flare fails a follow up Method 22 test, the Permittee shall repeat the procedures in paragraphs (I) through (III) of this section, until the flare passes a follow up test.

(e) The monthly VOC emissions calculations required in this permit shall account for the time periods between each failed detectable emissions or visible emissions test, as applicable, and subsequent compliant tests, assuming the emissions were uncontrolled.

(f) Where sufficient to meet the monitoring requirements in this section, the owner or operator may use a SCADA system to monitor and record the required data in paragraphs (a) through (d).

6. VOC Emissions Calculation Requirements: VOC emissions from each natural gas condensate and produced water storage tank at the facility due to working, standing, breathing and flashing losses for each calendar month shall be calculated using a generally accepted simulation model or software (e.g., ProMax) and the following:

(a) The total measured volume of natural gas condensate and produced water transferred to the storage tanks for the month;

(b) The VOC emissions control efficiency of the flare; and

(c) The actual physical and chemical properties of the natural gas condensate and its associated vapors from the most recent semiannual extended laboratory analysis of the natural gas condensate received at the facility.

7. Recordkeeping Requirements: The Permittee shall document and maintain the following records:

(a) The monthly and average daily barrels of condensate and produced water processed through the storage tanks;

(b) All natural gas condensate and produced water storage tank, closed-vent system, and flare inspections. All natural gas condensate and produced water storage tank closed-vent system, and flare inspection records shall include, at a minimum, the following information:

(i) The date of the inspection;
(ii) All documentation and/or images produced in the inspection;
(iii) The findings of the inspection;
(iv) Any corrective action taken; and
(v) The inspector's name and signature.

(c) The monthly VOC emissions, in tons, from each natural gas condensate and produced water storage tank and the emission calculations.

F. Requirements for Pneumatic Controllers

1. All pneumatic controllers shall be operated using only instrument air.

2. Records shall be kept of manufacturer's and/or vendor's specifications for each pneumatic controller.

G. 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.

H. 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 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 responsible official.

    (b) The report shall include CO and VOC emissions, as applicable.

    (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

    Documents may be submitted via electronic mail to R8AirReportEnforcement@epa.gov.

3. The Permittee shall promptly submit to the EPA a written report of any deviations of emission or operational limits specified in this permit and a description of 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 a deviation that would cause the Permittee to exceed the emission limits or operational limits in this permit if 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 CAA 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. *NAAQS and PSD Increments:* The permitted source shall not cause or contribute to a NAAQS 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 Emissions Units/Limits:* For proposed modifications, as defined at 40 CFR 49.152(d), that would increase an emissions unit 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 40 CFR 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, the Permittee 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:* Unless this permitted source of emissions is an existing source, 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 startup of this permitted source to the EPA within 60 days of such date, unless this permitted source of emissions is an existing source.

B. Authorization:

Authorized by the United States Environmental Protection Agency, Region 8

Carl Daly, Director Date
Air Program

United States Environmental Protection Agency
Region 8 Air Program
Air Pollution Control
40 CFR Part 49 Federal Minor New Source Permit to Construct
Technical Support Document for
Proposed Permit #SMNSR-UO-000007-2012.001

Anadarko Uintah Midstream, LLC
Cottonwood Wash Compressor Station
Uintah and Ouray Indian Reservation
Uintah County, Utah

In accordance with the requirements of the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49, this Federal permit to construct is being issued under authority of the Clean Air Act (CAA). The EPA has prepared this technical support document describing the conditions of this permit and presents information that is germane to this permit action.

Table of Contents

I. Introduction

On August 30, 2012 we received an application from Anadarko Uintah Midstream, LLC (Anadarko), requesting a synthetic minor permit for the Cottonwood Wash Compressor Station (Cottonwood Wash) in accordance with the requirements of the MNSR permitting program. We received a new application replacing the original application on September 20, 2013, with additional supplementary information on August 28, 2014, and July 21, 2015.

This permit action will apply to an existing facility operating on the Uintah and Ouray Indian Reservation in Utah. The exact location is Latitude 40.009722, Longitude -109.543889, in Uintah County, Utah.

This permit does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is only intended to incorporate required and requested enforceable emission limits and operational restrictions from a March 27, 2008, Federal Consent Decree (CD) between the United States of America (Plaintiff), and the State of Colorado, the Rocky Mountain Clean Air Action and the Natural Resources Defense Council (Plaintiff-Intervenors), and Kerr-McGee Corporation (Civil Action No. 07-CV-01034-EWN-KMT), and the September 20, 2013 synthetic MNSR application and supplementary submittals (see 40 CFR 49.151(c)(1)(ii)(d)) and 49.158(c)(4)(ii) and (iii)). Anadarko has requested legally and practically enforceable requirements for the installation and operation of a low-emission tri-ethylene glycol (TEG) dehydration system for control of volatile organic compound (VOC) emissions. Anadarko also requested enforceable requirements for installation and operation of a flare to control VOC emissions from natural gas condensate and produced water storage tanks at the facility, including an associated average daily production limit for natural gas condensate and produced water processed through the tanks. Additionally, Anadarko requested enforceable requirements for installation and operation of a catalytic control system on each of nine (9) natural gas-fired 4-stroke lean-burn (4SLB) reciprocating internal combustion engines (RICE) (used for natural gas compression at the facility, including associated carbon monoxide (CO) emission limits. Lastly, Anadarko requested enforceable requirement to install and operate only instrument air-driven pneumatic controllers.

The incorporation of the requirements from the CD, in addition to the limits requested by Anadarko in the application, consolidates the requirements originating from these documents into one permit. Upon compliance with the permit, the legally and practically enforceable reductions in emissions can be used when determining the applicability of other CAA requirements, such as the Prevention of Significant Deterioration (PSD) Permit Program at 40 CFR Part 52 and the Title V Operating Permit Program at 40 CFR Part 71 (Part 71).

II. Facility Description

Cottonwood Wash is a natural gas production facility used for natural gas compression and treatment. Natural gas from the field enters the station through a 10-inch intermediate pressure line at about 350 pounds per square inch (psig) or through an 8-, 10-, and 12-inch diameter low pressure pipeline at about 75 psig. Free liquids are dropped out in the inlet slug catcher and sent to the blow case system and onsite tank battery. The blow case system takes condensate recovered from the slug catcher and discharges it to a pipeline for further processing at the downstream gas plant. The remaining condensate and produced water is sent to three (3) 400 bbl storage tanks.

Natural gas from the inlet separators is sent to either the low pressure reciprocating compressors driven by the four (4) 1,340 and two (2) 1,775 hp RICE and compressed to about 350 psig or to the intermediate pressure reciprocating compressors driven by the three (3) 2,370 hp RICE and compressed to about 935 psig. These compressors are necessary to overcome the pipeline pressure to ensure transportation of the natural gas in the gathering pipeline system until it is further processed. There are also two (2) natural gas-fired 250 kilowatt (kW) turbine generators that supply the site with electricity.

The high pressure natural gas then goes through the Sulfa-Check liquid contactors for sulfur removal prior to passing through a low-emission dehydration unit to lower the water content of the gas to pipeline specifications. The glycol dehydration unit feeds lean glycol to the top of an absorber where it is contacted with the incoming wet natural gas stream entering from the bottom of the absorber. The glycol removes the water from the natural gas by physical absorption and is then carried out the bottom of the column. The now dry natural gas exits the top of the absorption column and is routed to a natural gas gathering pipeline.

The rich (wet) glycol stream is routed to a low-pressure flash separator where the hydrocarbon vapors are removed and any liquid hydrocarbons are skimmed off of the glycol. After leaving the flash vessel, the rich glycol is heated in a cross-exchanger and fed to the glycol regenerator. The glycol regenerator consists of a column, an overhead condenser, and a reboiler. The wet glycol flows down the reboiler while contacting hot gases rising up from the reboiler. The glycol is thermally heated to remove enough water vapor to regain the high glycol purity. Finally, the glycol is pumped back to the top of the absorber column to continually repeat the process while routing the dry natural gas to the gathering pipeline for sale. Cottonwood Wash utilizes a low-emission dehydration unit that captures the non-condensable portion of still vent and flash tank vapors and routes the vapor to the station inlet as natural gas product or to the station fuel system. The low-emission dehydration unit also employs electric glycol circulation pumps.

Pigging operations are conducted at the compressor station on the 12-inch pipeline approximately once per month and on the 10-inch line about twice a month. All pigged liquids are collected in the inlet separators. The only emissions generated during pigging operations are during the depressurization of the pig chamber to remove the pig.

The emission units identified in Table 1 are currently installed and/or operating at the facility. The information provided in this table is for informational purposes only and is not intended to be viewed as enforceable restrictions or open for public comment. The units and control requirements identified here either existed prior to any pre-construction permitting requirements or were approved/required through the alternative methods as identified below. Table 2, Facility-wide Emissions, provides an accounting of enforceable controlled emissions in tons per year (tpy).

Table 1. Existing Emission Units

Unit Description	Controls	Original Preconstruction Approval Date &/or Approval Details
Four (4) 4SLB, natural gas-fired RICE for gas compression, each with a maximum site rating of 1,340 hp.	Oxidation Catalyst	No pre-construction approval required for the installation of the engines. Installed prior to the promulgation of the MNSR permitting program. Control requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.

Two (2) 4SLB, natural gas-fired RICE for gas compression with a maximum site rating of 1,775 hp.	Oxidation Catalyst	No pre-construction approval required for the installation of the engines. Installed prior to the promulgation of the MNSR permitting program. Control requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.
Three (3) 4SLB, natural gas-fired RICE for gas compression with a maximum site rating of 2,370 hp.	Oxidation Catalyst	No pre-construction approval required for the installation of the engines. Installed prior to the promulgation of the MNSR permitting program. Control requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.
Three (3) 400 bbl* atmospheric condensate and produced water storage tanks.	Flare	No pre-construction approval required for the installation of the storage tanks. Installed prior to the promulgation of the MNSR permitting program. Control requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.
One (1) 80 MMscfd* tri-ethylene glycol (TEG) low-emission dehydration unit with: One (1) 1.4 MMBtu/hr TEG glycol Reboiler.;	Low-Emission Dehydrator Technology	No pre-construction approval required for the installation of the TEG dehydration unit. Installed prior to the promulgation of the MNSR permitting program. Control requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.
Pneumatic controllers (instrument air-driven)	None	No pre-construction approval required for the installation of the controllers. Installed and converted to instrument air prior to the promulgation of the MNSR permitting program. Instrument air conversion requirements established in the March 27, 2008 Consent Decree Civil Action No. 07-CV-01034-EWN-KMT.
Two (2) natural gas-fired turbine generator sets, each with a maximum site rating of 250 kW	None	No pre-construction approval required for the installation of the generator engines. Installed prior to the promulgation of the MNSR permitting program.
One (1) 0.25 MMBtu/hr* trace heater	None	No pre-construction approval required for the installation of the heater. Installed prior to the promulgation of the MNSR permitting program.
Facility Fugitives	None	No pre-construction approval required for the installation of the facility. Installed prior to the promulgation of the MNSR permitting program.

* bbl = barrel; MMBtu/hr = million British thermal units per hour; MMscfd = million standard cubic feet per day.

Table 2. Facility-wide Emissions

Pollutant	Controlled Potential Emissions (tpy)
PM	NA
PM_{10}	3.8
$PM_{2.5}$	NA
SO_2	0.3
NO_X	176.5
CO	232.0
VOC	122.2
Greenhouse Gases	
CO_2e (Total)	**54,307.7**
Hazardous Air Pollutants (HAP)	
Acetaldehyde	4.07
Acrolein	NA
Benzene	0.22
Ethyl-Benzene	NA
Toluene	NA
n-Hexane	0.56
Xylene	NA
Formaldehyde	11.2
2,2,4-Trimethylpentane	NA
Cyclohexane	NA
Total HAP**	**16.9**

PM – Particulate Matter
PM_{10} – Particulate Matter less than 10 microns in size
$PM_{2.5}$ – Particulate Matter less than 2.5 microns in size
SO_2 – Sulfur Dioxide
NO_X – Nitrogen Oxides
CO – Carbon Monoxide
VOC – Volatile Organic Compounds
CO_2 – Carbon dioxide
CH_4 – Methane
N_2O – Nitrous oxide
HFCs – Hydrofluorocarbons
PFCs – Perfluorocarbons
SF_6 – Sulfur hexafluoride
CO_2e – Equivalent CO_2. A measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP)

HFCs, PFCs, and SF_6 emissions are not created during oil and natural gas production operations.

NA – Not Available

*BTEX = benzene, toluene, ethylbenzene, and xylenes

**Total HAP is inclusive of but not limited to the individual HAP listed above.

III. Proposed Synthetic Minor Permit Action

A. Low-Emission Dehydration System

Natural gas often contains water vapor at the wellhead which must be removed to avoid pipeline corrosion and solid hydrate formation. The natural gas industry commonly uses the glycol absorption process to remove naturally occurring water from raw natural gas. Most commonly, the glycol absorbent used is TEG. The TEG dehydration process produces VOC and HAP emissions from pressure reduction of rich glycol (immediately post absorption and prior to stripping and regeneration) and from the stripping of the rich glycol to regenerate lean glycol to be reused in the process. The HAP emissions consist primarily of benzene, toluene, ethylbenzene and n-hexane.

A flash tank is typically utilized to separate these vapors at a pressure where they can be utilized for fuel. Distillation removes the absorbed water along with any remaining hydrocarbon, including VOC and HAP, from the glycol to the still column vent as overhead vapor. The typical form of emission control for conventional dehydrator still vents that emit the non-condensable portion of this overhead vapor is to route the vapors to a combustion device, such as a thermal oxidizer or reboiler burner to destroy the hydrocarbon content of the vapors.

Anadarko currently uses a low-emission glycol dehydrator at the Cottonwood Wash Compressor Station. This unit captures the non-condensable portion of still vent and flash tank vapors and recompress the vapor with a reciprocating or scroll compressor that routes the vapor to the station inlet as natural gas product, to fuel lines for power generation turbines or to the station fuel system. The unit also employs an electric glycol circulation pump, and except for the recompression of non-condensable vapors, resembles conventional glycol dehydrators in its configuration.

To ensure that the non-condensable vapor compression system is fully integrated into dehydrator operation such that the unit cannot be disabled so as to operate while venting to the atmosphere, the unit: 1) incorporates an integral vapor recovery function that prevents the dehydrator from operating independently of the vapor recovery function; 2) either returns the captured vapors to the inlet of the facility where the glycol dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and 3) thereby emits no more than 1.0 ton per year of VOC.

The low-emission glycol dehydrator has at least three (3) levels of protection to prevent emissions from occurring:

(a) Physical electrical hard-wiring between the vapor recovery unit (VRU) compressor and the glycol circulation pumps ensures that if the VRU compressor goes down, the glycol pump also shuts down, thereby halting the circulation of glycol through the wet gas as well as the emissions associated with the regeneration of glycol;

(b) A second level of protection redundancy has been incorporated by using the station Programmable Logic Controller (PLC) to shut down the dehydration system in the event the VRU compressor goes down; and

(c) A third level of protection is the routing of non-condensables directly to combustion devices in the stations that utilize micro-turbine electrical generators or central heat medium systems.

The unit was certified through a third-party independent engineering evaluation to have zero emissions of VOC from the routing of regenerator and flash tank overheads to an integrated VRU, and that safeguards exist to ensure that the dehydrator shuts down if the VRU is shut down for any reason. The independent engineering evaluation is available in the administrative docket for this permit.

We are proposing the emission, operational, testing, monitoring, recordkeeping, and reporting requirements in Table 3 for the Low-Emission Dehydrator. The proposed requirements are based, in part, on the unit specifications and independent engineering evaluation provided by Anadarko in the permit application and ensure that the requested emission limits are legally and practically enforceable.

Table 3. Proposed Low-Emission Dehydrator Emission, Operational, Testing, Monitoring, Recordkeeping, and Reporting Requirements

Type	Proposed Requirement
Construction and Operation	Install, operate and maintain a Low-Emission Dehydrator that is: • Limited to a maximum throughput of 85 million standard cubic feet per day (MMscfd) of natural gas; and • Certified as a "Low-Emission Dehydrator" that: o Incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function; o Either returns the captured vapors to the inlet of the facility where the dehydrator is located or routes the captured vapors to the facility's fuel gas supply header; and o Meets the control and operational requirements specified in the permit. Route all non-condensable emissions from the process vent and flash tank through a closed-vent system to a VRU with reciprocating or scroll compressors. The Low-Emission Dehydrator and VRU system must have at least three (3) levels of protection to prevent VOC emissions: • Physical electric hard-wiring between VRU compressors and TEG circulation pump to ensure if VRU ceases to operate, TEG pump also shuts down, halting circulation of TEG through wet gas and preventing TEG regeneration emissions; • Incorporate second level protection into Programmable Logic controller using instrumentation to shut down Low-Emission Dehydrator if VRU ceases to operate; and

	• Third level protection to pump non-condensable gases from Low-Emission Dehydrator exclusively to station inlet or fuel system for use as fuel and ensurance it is not used for blanket gas in storage tanks or vented to atmosphere.
Emission Limits	Limit VOC emissions from the Low-Emission Dehydrator to 1.0 tons of VOC in any consecutive 12-month period.
Emission Calculations	• VOC emissions for Low-Emission Dehydrator calculated in tons and recorded at end of each month. • Calculation of rolling consecutive 12-month VOC emissions. • Calculations using generally accepted simulation model or software (e.g., ProMax and GRI-GLYCalc™ Version 4.0 or higher).
Monitoring	• Daily inspections to ensure proper operation according to manufacturer recommendations. • Quarterly audio, visual and olfactory inspections of closed-vent system for leaks of hydrocarbon emissions. Address any leaks detected no later than 15 days after initial detection. • Install, operate and maintain meter to continuously measure natural gas flowrate to the Low-Emission Dehydrator. Inspect meter monthly to ensure proper operation according to manufacturer recommendations. • Calculate and document actual monthly average natural gas flowrate.
Recordkeeping	Keep records of all manufacturer specifications, all VOC monthly and 12-month rolling emissions calculations, and

	all required monitoring, maintenance, inspections and repairs.
Reporting	Submit a summary of all monthly and 12-month rolling VOC emissions calculations and all maintenance, inspections, and performance tests conducted in each annual report to the EPA.

The proposed emission restrictions will result in a total of 1.0 tpy of VOC from the Low-Emission Dehydrator. These controlled emissions are based on the dehydrator operating a maximum of 8,760 hours in a year, at a maximum capacity of 85 MMscfd, and as a certified "Low-Emission Dehydrator."

B. 4SLB Natural Gas-Fired Compressor Engines and Controls

The Compressor Station operates nine (9) natural gas-fired 4SLB engines and the primary form of emission control for natural gas-fired lean-burn engines is catalytic control systems, most commonly systems that use oxidation catalysts. The oxidation catalyst is effective for control of CO, VOC, and formaldehyde. These catalysts do not typically control NOx emissions. However, lean-burn engines are designed to operate with more dilute natural gas streams (a higher air-to-fuel ratio) than rich-burn engines. Because they operate on more dilute natural gas streams, lean-burn engines also operate at lower combustion temperatures producing less NO_X emissions than rich-burn engines.

The CD contains requirements to control these engines using oxidation catalyst control systems. Anadarko requested enforceable restrictions that include the use of an oxidation catalyst control system on each engine and engine-specific CO emission limits based on the catalyst manufacturer guaranteed emission reduction achievable by the control devices.

Based on our review of Anadarko's permit application, we are proposing the construction, operation, emissions, testing, monitoring, recordkeeping, and reporting requirements in Table 4 for these engines, that are consistent with the requirements in the CD, and are including any necessary testing, monitoring, and recordkeeping requirements, pursuant to 40 CFR 49.151(ii)(C), to ensure that the requested emission limits are legally and practically enforceable:

Table 4. Proposed Engine Construction, Operation, Emissions, Testing, Monitoring, Recordkeeping, and Reporting Requirements

Type	**Proposed Requirement**
Construction, Control and Operation	Install, continuously operate and maintain a catalytic control system on each engine capable of reducing emissions of CO to meet the unit-specific emission limits. Install, operate and maintain temperature sensing devices before the catalytic control system on each engine.

	Maintain exhaust of each engine between 450ºF and 1,350ºF (except during startups, not to exceed 30 minutes). During operation, maintain pressure drop across each catalyst bed to within ± 2 inches of water from the baseline pressure drop reading taken during the initial performance test. Follow engine and control manufacturer recommended maintenance schedules and procedures, or equivalent procedures developed by the vendor or Permittee, to ensure optimum engine and control performance.
Emission Limits	Limit emissions of CO from the exhausts of the engine catalytic control systems as follows: • Each 1,340 hp engine: 1.21 grams per hp-hour (g/hp-hr). • Each 1,775 hp or 2,370 hp engine: 1.63 g/hp-hr.
Performance Testing	Initial performance testing for compliance with the CO emission limits within 180 days after the effective date of the permit. Subsequent performance tests within six (6) months of most recent test. After compliance is demonstrated for two consecutive tests, the testing frequency shall be reduced to annually if facility-wide CO emissions are less than 150 tpy, calculated based on the results of the most recent test and 8,760 hours per year of operation. If facility-wide CO emissions exceed 150 tpy CO after any one subsequent test, then semi-annual performance testing shall be resumed. Performance tests for compliance with the CO emission limits within 90 calendar days of each replacement of the catalyst or startup of each rebuilt or replaced engine. Performance tests shall be conducted using a portable analyzer to measure oxygen (O_2), CO, and NO_X in accordance with EPA

	Reference Method 10 at 40 CFR part 60, Appendix A, or American Society of Testing and Materials (ASTM) method D6522-00 (2005). Measurements to determine O_2 and NO_X shall be performed simultaneously with measurements for CO concentration. *(Note: although no NO_X emission limits are proposed, the requirement is included as an indicator to ensure engines are not being tuned immediately prior to or during performance tests)*
Monitoring	Follow each engine maintenance plan. Continuously monitor engine exhaust temperature at the inlet to the catalyst bed. Measure pressure drop across the catalyst bed every 30 days. Take specific corrective actions if engine exhaust temperatures exceed acceptable ranges specified or if pressure drop across catalyst beds exceed ± two (2) inches of water from the baseline pressure drop.
Recordkeeping	Keep records of all maintenance and monitoring conducted, all performance test results, all exceedances of acceptable operating parameters and subsequent corrective actions, and all deviations from permit conditions.
Reporting	Submit all performance test reports to the EPA. Include a summary of all maintenance and monitoring conducted, corrective actions, and all deviations from permit conditions in each required annual report to the EPA.

These proposed CO emission limits will result in a total of 229.8 tpy of CO for these nine (9) engines. The potential controlled emissions are based on the engines operating a maximum of 8,760 hours in a year and at the specified maximum horsepower ratings and accounting for catalytic control system manufacturer guaranteed CO control efficiencies of 93%.

C. Condensate Tanks and Controls

Natural gas from the field enters the Cottonwood Wash Compressor Station at various pressures ranging between 75 pounds per square inch (psig) to approximately 350 psig. Free liquids are dropped out in the inlet slug catcher from which condensate is routed to the blowcase system, which sends it to the gathering pipeline for downstream processing, and water is routed to the above ground storage tank battery. The water contains remnant condensate because the blowcase is not 100 percent efficient. Therefore, the storage tanks experience working, standing, breathing and flash emissions containing VOC both from ongoing water storage and from the dumping of water at higher pressure in the slug catcher to the storage tanks at lower atmospheric pressure. The storage tanks are controlled by a flare to destroy at least 95.0 percent of the mass content of VOC in the emissions via combustion.

Based on our review of Anadarko's permit application, we are proposing the construction, operation, emissions, testing, monitoring, recordkeeping, and reporting requirements in Table 5 for the condensate storage tanks, which are consistent with those for similar controlled storage tanks subject to the NSPS for Crude Oil and Natural Gas Production, Transmission and Distribution at 40 CFR part 60, subpart OOOO, and are including any necessary testing, monitoring, and recordkeeping requirements, pursuant to 40 CFR 49.151(ii)(C), to ensure that the requested emission limits are legally and practically enforceable:

Table 5. Proposed Storage Tank Battery Construction, Operation, Emissions, Testing, Monitoring, Recordkeeping, and Reporting Requirements

Type	Proposed Requirement
Construction, Control and Operation	Install, continuously operate and maintain no more than three (3) natural gas condensate and produced water storage tanks, each limited to a maximum storage capacity of 400 bbl. Route all natural gas condensate and produced water storage tank emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare designed, continuously operated and maintained to reduce mass content of uncontrolled VOC emissions by at least 95.0 percent by weight. The closed-vent system shall route all gases vapors, and fumes emitted from the natural gas condensate and produced water storage tanks to the flare and be designed and maintained to operate with no detectable emissions. The flare shall be: • Operated at all times natural gas condensate and produced water

	storage tank emissions are routed to it; • Equipped and operated with a liquid knockout system to collect condensable vapors; • Equipped with a flash-back flame arrestor; • Equipped with a continuous burning pilot flame, thermocouple, and malfunction alarm and notification system if the pilot flame fails or an electronically controlled auto-ignition system with a malfunction and notification system if the pilot flame fails while natural gas condensate and produced water storage tank emissions are routed to it; and • Maintained in a leak-free condition and operated with no visible smoke emissions.
Production Limit	Limit throughput of natural gas condensate and produced water processed through the storage tanks to 13 bbl per day on average.
Testing and Monitoring Requirements	• Measure the bbl of natural gas condensate and produced water stored in the tanks each time liquids are unloaded from the storage tanks using process flow meters and/or sales records. At the end of each month, calculate a daily average throughput. • Weekly auditory, visual and olfactory (AVO) inspections of storage tank thief hatches, covers, seals, pressure relief valves and the closed-vent system (performed while storage tanks are being filled). Repair any deficient conditions within 15 days of identification. • Monthly visual inspections of peak pressure and vacuum values in each storage tank and the closed-vent system using EPA Methods 21 and 22, as appropriate, to ensure pressure relief set points are not being exceeded resulting in venting of

	emissions and possible damage to equipment and to ensure the closed-vent system operates with no detectable emissions. • Monitor operation of the flare using the malfunction alarm and remote notification system, weekly physical inspections, and continuous monitoring of variable operating parameters specified in the manufacturer's written specifications.
VOC Emissions Calculation	Calculate monthly VOC emissions from each natural gas condensate and produced water storage tank due to working, standing, breathing and flashing losses.
Recordkeeping	• Monthly and daily average bbl of condensate and produced water processed through the storage tanks. • All required inspections. • Monthly VOC emissions from the natural gas condensate and produced water storage tanks and calculations.
Reporting	Include a summary of all maintenance and monitoring conducted, corrective actions, and all deviations from permit conditions in each required annual report to the EPA.

D. Pneumatic Controllers

The CD contains a requirement that all pneumatic controllers be operated using instrument air. Therefore, we are proposing such a condition in the permit.

IV. Air Quality Review

The MNSR regulations at 40 CFR 49.154(d) require that an Air Quality Impact Assessment (AQIA) modeling analysis be performed if there is reason to be concerned that new construction would cause or contribute to a National Ambient Air Quality Standard (NAAQS) or PSD increment violation. If an AQIA reveals that the proposed construction could cause or contribute to a NAAQS or PSD increment violation, such impacts must be addressed before a pre-construction permit can be issued.

The emissions at this existing facility will not be increasing due to this permit action and the emissions will continue to be well controlled at all times. In addition, this permit action does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations and the substantive requirements of the CD (emission controls and reductions) have already been fulfilled at this facility. In short, this action will have no adverse air quality impacts; therefore, we have determined that an AQIA modeling analysis is not required for this action.

V. Tribal Consultations and Communications

We offer tribal government leaders an opportunity to consult on each permit action. We ask the tribal government leaders to respond to our offer to consult within 30 days of receiving the offer. We offered the Chairperson of the Ute Tribe an opportunity to consult on this permit action via letter dated February 5, 2015. To date, the EPA has not received a request for such consultation.

All minor source applications (synthetic minor, minor modification to an existing facility, new true minor, and general permit) are submitted to both the tribe and the EPA per the application instructions (see https://www.epa.gov/caa-permitting/tribal-nsr-permits-region-8). The tribe has 10 business days from the receipt of the application to communicate to the EPA any preliminary questions and comments on the application. In the event an AQIA is triggered, we email a copy of that document to the tribe within 5 business days from the date that we receive it.

Additionally, we notify the tribe of the public comment period for the proposed permit and provide copies of the notice of public comment opportunity to post in various locations of their choosing on the Reservation. We also notify the tribe of the issuance of the final permit.

VI. Environmental Justice

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations."

The EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. The EPA's goal is to address the needs of overburdened populations or communities to participate in the permitting process. *Overburdened* is used to describe the minority, low-income, tribal and indigenous populations or communities in the United States that potentially experience disproportionate environmental harms and risks due to exposures or cumulative impacts or greater vulnerability to environmental hazards.

This discussion describes our efforts to identify environmental justice communities and assess potential effects in connection with issuing this permit in Duchesne County, Utah, within the exterior boundaries of the Uintah and Ouray Indian Reservation.

A. Environmental Impacts to Potentially Overburdened Communities

This permit action does not authorize the construction of any new air emission sources, or air emission increases from existing units, nor does it otherwise authorize any other physical modifications to the associated facility or its operations. The air emissions at the existing facility will not increase due to the associated action and the emissions will continue to be well controlled at all times. This action will have no adverse air quality impacts.

Furthermore, the permit contains a provision stating, "*The permitted source shall not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.*" Noncompliance with this permit provision is a violation of the permit and is grounds for enforcement action and for permit termination or revocation. As a result, we conclude that issuance of the aforementioned permit will not have disproportionately high or adverse human health effects on communities in the vicinity of the Uintah and Ouray Indian Reservation.

B. Enhanced Public Participation

Given the presence of potentially overburdened communities in the vicinity of the facility, we are providing an enhanced public participation process for this permit.

1. Interested parties can subscribe to an EPA listserve that notifies them of public comment opportunities on the Uintah and Ouray Indian Reservation for proposed air pollution control permits via email at https://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8.

2. All minor source applications (synthetic minor, modification to an existing facility, new true minor or general permit) are submitted to both the tribe and the EPA per the application instructions (see https://www.epa.gov/caa-permitting/tribal-nsr-permits-region-8).

3. The tribe has 10 business days to communicate to the EPA any preliminary questions and comments on the application.

4. In the event an AQIA is triggered, we email a copy of that document to the tribe within 5 business days from the date we receive it.

5. We notify the tribe of the public comment period for the proposed permit and provide copies of the notice of public comment opportunity to post in various locations of their choosing on the Reservation. We also notify the tribe of the issuance of the final permit.

6. We offer the tribal government leaders an opportunity to consult on each proposed permit action. The tribal government leaders are asked to respond to the EPA's offer to consult within 30 days of receiving the letter.

VII. Authority

Requirements under 40 CFR Part 49 to obtain a permit apply to new and modified minor stationary sources, and minor modifications at existing major stationary sources ("major" as defined in 40 CFR 52.21). In addition, the MNSR permitting program provides a mechanism for an otherwise major stationary source to voluntarily accept restrictions on its potential to emit to become a synthetic minor source. We are charged with direct implementation of these provisions where there is no approved Tribal implementation plan for implementation of the MNSR regulations. Pursuant to Section 301(d)(4) of the CAA (42 U.S.C. Section 7601(d)), we are authorized to implement the MNSR regulations at 40 CFR Part 49 in Indian country. The Cottonwood Wash Compressor Station is located on Indian country lands within the exterior boundaries of the Uintah and Ouray Indian Reservation in Utah. The exact location is Latitude 40.009722, Longitude -109.543889, in Uintah County, Utah.

VIII. Public Notice and Comment, Hearing and Appeals

A. Public Comment Period

In accordance with 40 CFR 49.157, we must provide public notice and a 30-day public comment period to ensure that the affected community and the general public have reasonable access to the application and proposed permit information. The application, the proposed permit, this technical support document, and all supporting materials for the proposed permit are available at:

Ute Indian Tribe
Energy and Minerals Department
P.O. Box 70
988 South 7500 East, Annex Building
Fort Duchesne, Utah 84026
Contact: Minnie Grant, Air Coordinator, 435-725-4900 or minnieg@utetribe.com

and

U.S. EPA
Region 8 Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129
Contact: Claudia Smith, Environmental Scientist, 303-312-6520 or smith.claudia@epa.gov

All documents are available for review at our office Monday through Friday from 8:00 a.m. to 4:00 p.m. (excluding Federal holidays). Additionally, the proposed permit and technical support document can be reviewed on our website at: https://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8.

Any person may submit written comments on the proposed permit and may request a public hearing during the public comment period. These comments must raise any reasonably ascertainable issues with supporting arguments by the close of the public comment period (including any public hearing). Comment may be sent to the EPA address above, or sent via an email to r8airpermitting@epa.gov, with the topic "Comments on SMNSR Permit for the Anadarko Cottonwood Wash Compressor Station".

B. Public Hearing

A request for a public hearing must be in writing and must state the nature of the issues proposed to be raised at the hearing. We will hold a hearing whenever there is, on the basis of requests, a significant degree of public interest in a proposed permit. We may also hold a public hearing at our discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision.

C. Final Permit Action

In accordance with 40 CFR 49.159, a final permit becomes effective 30 days after permit issuance, unless: (1) a later effective date is specified in the permit; (2) appeal of the final permit is made as detailed in the next section; or (3) we may make the permit effective immediately upon issuance if no comments resulted in a change or denial of the proposed permit. We will send notice of the final permit action to any individual who commented on the proposed permit during the public comment period. In addition, the source will be added to a list of final permit actions which is posted on our website at: https://www.epa.gov/caa-permitting/caa-permits-issued-epa-region-8. Anyone may request a copy of the final permit at any time by contacting the Tribal Air Permit Program at (800) 227–8917 or sending an email to r8airpermitting@epa.gov.

D. Appeals to the Environmental Appeals Board

In accordance with 40 CFR 49.159, within 30 days after a final permit decision has been issued, any person who filed comments on the proposed permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) to review any condition of the permit decision. The 30-day period within which a person may request review under this section begins when we have fulfilled the notice requirements for the final permit decision. Motions to reconsider a final order by the EAB must be filed within 10 days after service of the final order. A petition to the EAB is under Section 307(b) of the CAA, a prerequisite to seeking judicial review of the final agency action. For purposes of judicial review, final agency action occurs when we issue or deny a final permit and agency review procedures are exhausted.

MEMO TO FILE

DATE: December 5, 2016

SUBJECT: Uintah and Ouray Indian Reservation, Cottonwood Wash Compressor Station; Anadarko Uintah Midstream, LLC, Environmental Justice

FROM: Colin Schwartz, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal, UO, Anadarko Uintah Midstream, LLC. Cottonwood Wash CS
SMNSR-UO-000007-2012.001, 9/6/2012
FRED # 98582

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations."

The EPA defines "Environmental Justice" as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. The EPA's goal with respect to Environmental Justice in permitting is to enable overburdened communities to have full and meaningful access to the permitting process and to develop permits that address environmental justice issues to the greatest extent practicable under existing environmental laws. *Overburdened* is used to describe the minority, low-income, tribal and indigenous populations or communities in the United States that potentially experience disproportionate environmental harms and risks as a result of greater vulnerability to environmental hazards.

This discussion describes our efforts to identify environmental justice communities and assess potential effects in connection with issuing this permit in Uintah County, Utah, on Indian country lands within the Uintah and Ouray Indian Reservation.

Region 8 Air Program Determination

Based on the findings described in the following sections of this memorandum, we conclude that issuance of the aforementioned permit is not expected to have disproportionately high or adverse human health effects on overburdened communities in the vicinity of the facility.

Permit Request

The EPA received an application from Anadarko Uintah Midstream, LLC (Anadarko) requesting a synthetic minor permit for the existing Ponderosa Compressor Station in accordance with the requirements of the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49. Anadarko requested legally and practically enforceable emissions and operational limitations that

recognize controls of VOC TEG dehydration system, produced water storage tank and pneumatic controller emissions, and CO engine emissions.

This permit does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is only intended to incorporate requested enforceable emission limits and operational restrictions from the MNSR application. Anadarko requested requirements to control VOC emissions from one (1) tri-ethylene glycol dehydration system using a vapor recovery unit, nine (9) existing engines used for natural gas compression that will be operated as a 4-stroke lean-burn engine with catalytic control systems that are capable to reduce the uncontrolled emissions of CO, three (3) tanks used to store natural gas condensate and produced water which route all natural gas condensate and produced water emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare, and for all pneumatic controllers to be operated using only instrument air.

Upon compliance with this permit, Anadarko will have legally and practically enforceable restrictions on emissions that can be used when determining the applicability of other CAA permitting requirements, such as under the Prevention of Significant Deterioration Permit Program at 40 CFR Part 52 and the Title V Operating Permit Program at 40 CFR Part 71. The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

The facility is located at:

Sec 27 T9S R21E
Latitude 40.009722, Longitude -109.543889

Air Quality Review

The MNSR regulations at 40 CFR 49.154(d) require that an Air Quality Impact Assessment (AQIA) modeling analysis be performed if there is reason to be concerned that new construction would cause or contribute to a National Ambient Air Quality Standard (NAAQS) or PSD increment violation. If an AQIA reveals that the proposed construction could cause or contribute to a NAAQS or PSD increment violation, such impacts must be addressed before a pre-construction permit can be issued. Because the permit actions do not authorize the construction of any new emission sources, or emission increases from existing units we have determined that an AQIA modeling analysis is not required for this action.

For purposes of Executive Order 12898 on environmental justice, the EPA has recognized that compliance with the NAAQS is "emblematic of achieving a level of public health protection that, based on the level of protection afforded by a primary NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to the exposure to relevant criteria pollutants." *In re Shell Gulf of Mexico, Inc. & Shell Offshore, Inc.*, 15 E.A.D., slip op. at 74 (EAB 2010). This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

Environmental Impacts to Potentially Overburdened Communities

This permit action does not authorize the construction of any new air emission sources, or air emission increases from existing units, nor does it otherwise authorize any other physical modifications to the associated facility or its operations. The air emissions at the existing facility will not increase due to the associated action.

Furthermore, the permit contains a provision stating, "*The permitted source shall not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.*" Noncompliance with this permit provision is a violation of the permit and is grounds for enforcement action and for permit termination or revocation. As a result, we conclude that issuance of the aforementioned permit will not have disproportionately high or adverse human health effects on communities in the vicinity of the Uintah and Ouray Indian Reservation.

Tribal Consultation and Enhanced Public Participation

Given the presence of potentially overburdened communities in the vicinity of the facility, we are providing an enhanced public participation process for this permit.

1. Interested parties can subscribe to an EPA email list that notifies them of public comment opportunities on the Uintah and Ouray Indian Reservation for proposed air pollution control permits via email at https://www.epa.gov/caa-permitting/caa-permit-public-comment-opportunities-region-8.

2. All minor source applications (synthetic minor, modification to an existing facility, new true minor or general permit) are submitted to both the Tribe and us per the application instructions (see https://www.epa.gov/caa-permitting/tribal-nsr-permits-region-8).

3. The Tribe has 10 business days to respond to us with questions and comments on the application.

4. In the event an AQIA is triggered, we email a copy of that document to the Tribe within 5 business days from the date we receive it.

5. We notify the Tribe of the public comment period for the proposed permit and provide copies of the notice of public comment opportunity to post in various locations of their choosing on the Reservation. We also notify the Tribe of the issuance of the final permit.

MEMO TO FILE

DATE: December 5, 2016

SUBJECT: Uintah and Ouray Indian Reservation, Cottonwood Wash Compressor Station; Anadarko Uintah Midstream, LLC., Endangered Species Act

FROM: Colin Schwartz, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal, UO, Anadarko Uintah Midstream, LLC. Cottonwood Wash CS
SMNSR-UO-000007-2012.001, 9/6/2012
FRED # 98582

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. §1536, and its implementing regulations at 50 CFR, part 402, the EPA is required to ensure that any action authorized, funded, or carried out by the Agency is not likely to jeopardize the continued existence of any Federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. Under ESA, those agencies that authorize, fund, or carry out the federal action are commonly known as "action agencies." If an action agency determines that its federal action "may affect" listed species or critical habitat, it must consult with the U.S. Fish and Wildlife Service (FWS). If an action agency determines that the federal action will have no effect on listed species or critical habitat, the agency will make a "no effect" determination. In that case, the action agency does not initiate consultation with the FWS and its obligations under Section 7 are complete.

In complying with its duty under ESA, the EPA, as the action agency, examined the potential effects on listed species and designated critical habitat relating to issuing this Clean Air Act (CAA) synthetic minor New Source Review permit in Uintah County, Utah, on Indian country lands within the Uintah and Ouray Indian Reservation.

Region 8 Air Program Determination

The EPA has concluded that the proposed synthetic minor NSR permit actions will have "*No effect*" on listed species or critical habitat. The proposed permit action does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the associated facility or its operations. Because the EPA has determined that the federal action will have no effect, the agency made a *"No effect"* determination, did not initiate consultation with the FWS and its obligations under Section 7 are complete.

Permit Request

The EPA received an application from Anadarko Uintah Midstream, LLC (Anadarko) requesting a synthetic minor permit for the existing Ponderosa Compressor Station in accordance with the requirements of the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49. Anadarko requested legally and practically enforceable emissions and operational limitations that

recognize controls of VOC TEG dehydration system, produced water storage tank and pneumatic controller emissions, and CO engine emissions.

This permit does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is only intended to incorporate requested enforceable emission limits and operational restrictions from the MNSR application. Anadarko requested requirements to control VOC emissions from one (1) tri-ethylene glycol dehydration system using a vapor recovery unit, nine (9) existing engines used for natural gas compression that will be operated as a 4-stroke lean-burn engine with catalytic control systems that are capable to reduce the uncontrolled emissions of CO, three (3) tanks used to store natural gas condensate and produced water which route all natural gas condensate and produced water emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare, and for all pneumatic controllers to be operated using only instrument air.

Upon compliance with this permit, Anadarko will have legally and practically enforceable restrictions on emissions that can be used when determining the applicability of other CAA permitting requirements, such as under the Prevention of Significant Deterioration Permit Program at 40 CFR Part 52 and the Title V Operating Permit Program at 40 CFR Part 71. The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

The facility is located at:

Sec 27 T9S R21E
Latitude 40.009722, Longitude -109.543889

Conclusion

The EPA has concluded that the proposed synthetic minor NSR permit action will have "*No effect*" on listed species or critical habitat. These proposed permit action does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action. Because the EPA has determined that the federal action will have no effect, the agency will make a *"No effect"* determination. In that case, the EPA does not initiate consultation with the FWS and its obligations under Section 7 are complete.

<u>MEMO TO FILE</u>

DATE: December 5, 2016

SUBJECT: Uintah and Ouray Indian Reservation, Cottonwood Wash Compressor Station; Anadarko Uintah Midstream, LLC., National Historic Preservation Act

FROM: Colin Schwartz, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal, UO, Anadarko Uintah Midstream, LLC. Cottonwood Wash CS
SMNSR-UO-000007-2012.001, 9/6/2012
FRED # 98582

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to take into account the effects of their undertakings on historic properties and afford the Advisory Council on Historic Preservation (ACHP) a reasonable opportunity to comment with regard to such undertakings. Under the ACHP's implementing regulations at 36 C.F.R. Part 800, Section 106 consultation is generally with state and tribal historic preservation officials in the first instance, with opportunities for the ACHP to become directly involved in certain cases. An "undertaking" is "a project, activity, or program funded in whole or in part under the direct or indirect jurisdiction of a Federal agency, including those carried out by or on behalf of a Federal agency; those carried out with Federal financial assistance; and those requiring a Federal permit, license or approval." 36 C.F.R. § 800.16(y).

Under the NHPA Section 106 implementing regulations, if an undertaking is a type of activity that has the potential to cause effects on historic properties, assuming any are present, then federal agencies consult with relevant historic preservation partners to determine the area of potential effect (APE) of the undertaking, to identify historic properties that may exist in that area, and to assess and address any adverse effects that may be caused on historic properties by the undertaking. If an undertaking is a type of activity that does not have the potential to cause effects on historic properties, the federal agency has no further obligations. 36 C.F.R. § 800.3(a)(1).

This memorandum describes EPA's efforts to assess potential effects on historic properties in connection with to issuing this Clean Air Act (CAA) synthetic minor New Source Review permit in Uintah County, Utah, on Indian country lands within the Uintah and Ouray Indian Reservation. As explained further below, EPA is finding that the proposed action does not have the potential to cause effects on historic properties, even assuming such historic properties are present.

Permit Request

The EPA received an application from Anadarko Uintah Midstream, LLC (Anadarko) requesting a synthetic minor permit for the existing Ponderosa Compressor Station in accordance with the requirements of the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49. Anadarko requested legally and practically enforceable emissions and operational limitations that

recognize controls of VOC TEG dehydration system, produced water storage tank and pneumatic controller emissions, and CO engine emissions.

This permit does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is only intended to incorporate requested enforceable emission limits and operational restrictions from the MNSR application. Anadarko requested requirements to control VOC emissions from one (1) tri-ethylene glycol dehydration system using a vapor recovery unit, nine (9) existing engines used for natural gas compression that will be operated as a 4-stroke lean-burn engine with catalytic control systems that are capable to reduce the uncontrolled emissions of CO, three (3) tanks used to store natural gas condensate and produced water which route all natural gas condensate and produced water emissions from working, standing, breathing and flashing losses through a closed-vent system to a flare, and for all pneumatic controllers to be operated using only instrument air.

Upon compliance with this permit, Anadarko will have legally and practically enforceable restrictions on emissions that can be used when determining the applicability of other CAA permitting requirements, such as under the Prevention of Significant Deterioration Permit Program at 40 CFR Part 52 and the Title V Operating Permit Program at 40 CFR Part 71. The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

The facility is located at:

Sec 27 T9S R21E
Latitude 40.009722, Longitude -109.543889

Finding of No Potential to Cause Effects

The EPA has reviewed the proposed actions for potential impacts on historic properties. Because the activities authorized by the EPA permits does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations, the Agency finds that this project does not have the potential to cause effects on historic properties, even assuming any are present.

State and Tribal Consultation

Because this undertaking is a type of activity that does not have the potential to cause effects on historic properties, the EPA has no further obligations under Section 106 of the National Historic Preservation Act or 36 C.F.R. part 800.

Smith, Claudia

From:	Doolittle, Katherine <Katherine.Doolittle@anadarko.com>
Sent:	Tuesday, July 21, 2015 10:50 AM
To:	Smith, Claudia
Cc:	Schlichtemeier, Chad
Subject:	RE: Cottonwood Wash Compressor Station Synthetic Minor NSR Permit Application
Attachments:	Cottonwood Calcs.pdf
Follow Up Flag:	Follow up
Flag Status:	Flagged

Claudia –

There are three-400 bbl combination condensate/produced water tanks on location, all controlled by the flare.

The two produced water tanks in question were removed around the time of the slug catcher installation. It appears we accidentally kept this "TANKS" line item from these (removed) produced water tanks. This line item has been removed from the PTE calculations in the attached PDF.

Thanks for catching this and let us know if you have further questions.

Thank you,

Katherine Doolittle | Staff HSE Representative
Anadarko Petroleum Corporation | 1099 18th Street | Denver, CO 80202
Work: 720-929-6511 | Cell: 720-216-7394 | Fax: 720-929-7511

From: Smith, Claudia [mailto:Smith.Claudia@epa.gov]
Sent: Friday, July 17, 2015 3:53 PM
To: Doolittle, Katherine
Subject: Cottonwood Wash Compressor Station Synthetic Minor NSR Permit Application

Hi, Katherine,

I am working on drafting the synthetic minor NSR permit for the Cottonwood Wash Compressor Station and a question came up. The two pages in the attached PDF, from the "Revised Synthetic Minor NSR Permit Application under Part 49" dated September 19, 2013 appear to be inconsistent.

The first page, from Attachment B, indicates there are 3 produced water tanks for which Anadarko is requesting enforceable conditions for routing emissions to a flare. The second page, "Total Facility PTE Emissions" found later in the application appears to indicate there is a condensate storage tank battery ("TANKBAT") with no indication of the number, size, or PTE, a tank battery flare ("TANKFLR"), and then further down is also two 400-bbl Produced Water Tanks ("TANKS"). How many condensate tanks comprise the tank battery? How many produced water tanks are there? Are the enforceable flare conditions being requested for the condensate tanks only, the produced water tanks only, or all of the storage tanks?

Thanks for your assistance,

Claudia

Claudia Young Smith
Environmental Scientist
US EPA Region 8 Air Program
Phone: (303) 312-6520
Fax: (303) 312-6064
http://www2.epa.gov/region8/air-permitting

****
US EPA Region 8
1595 Wynkoop Street
Mail Code 8P-AR
Denver, Colorado 80202
****

From: R8printer@epa.gov [mailto:R8printer@epa.gov]
Sent: Friday, July 17, 2015 3:36 PM
To: Smith, Claudia
Subject:

Total Facility PTE Emissions
Cottonwood Compressor Station

Unit	Description	NOx	CO	VOC	SOx	PM10	CO2e	CH_2O	HAPs
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
ENG1	1340 hp Cat G3516 LE Engine	25.9	15.6	9.1	0.03	0.4	4713.7	0.9	1.3
ENG2	1340 hp Cat G3516 LE Engine	25.9	15.6	9.1	0.03	0.4	4713.7	0.9	1.3
ENG4	1340 hp Cat G3516 LE Engine	25.9	15.6	9.1	0.03	0.4	4713.7	0.9	1.3
ENG5	1340 hp Cat G3516 LE Engine	25.9	15.6	9.1	0.03	0.4	4713.7	0.9	1.3
ENG-WEST-2	2370 hp Cat G3608 LE Engine	16.0	37.2	16.0	0.04	0.7	7430.7	1.4	2.1
ENG-WEST-3	2370 hp Cat G3608 LE Engine	16.0	37.2	16.0	0.04	0.7	7430.7	1.4	2.1
ENG-WEST-4	2370 hp Cat G3608 LE Engine	16.0	37.2	16.0	0.04	0.7	7430.7	1.4	2.1
ENG-WEST-5	1775 hp Cat G3606 LE Engine	12.0	27.9	12.0	0.0	0.0	5967.4	1.6	2.2
ENG-WEST-6	1775 hp Cat G3606 LE Engine	12.0	27.9	12.0	0.0	0.0	5967.4	1.6	2.2
REBLR-2	1.4 MMBtu/hr Dehy Reboiler	0.6	0.5	0.0	0.003	0.0	717.5	0.0	0.0
DEHY-LO	80 MMscfd Low Emissions Dehy			1.0					
TANKBAT	Condensate Storage Tank Battery								
TANKFLR	Tank Battery Flare	0.3	1.6	0.8			508.6		0.0
FUG	Facility Fugitives			12.2					0.8
GEN1	250kW Ingersoll-Rand Turbine Generator	0.01	0.01	0.00	0.00	0.00			0.00
GEN2	250kW Ingersoll-Rand Turbine Generator	0.01	0.01	0.00	0.00	0.00			0.00
HTR	0.25 MMBtu/hr Trace Heater	0.10	0.08	0.01	0.000	0.01		0.00	0.00
Facility Totals		**176.5**	**232.0**	**122.2**	**0.3**	**3.8**	**54307.7**	**11.2**	**16.9**

Anadarko Uintah Midstream LLC
P.O. Box 173779, Denver, Colorado80217-3779
720-929-6000 Fax 720-929-7000

August 26, 2014

SENT VIA CERTIFIED MAIL No.: 7012 3460 0000 6485 8138

Mr. Eric Wortman
U.S. EPA, Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129

RE: Additional Information/CBI Request Clarification
Revised Synthetic Minor NSR Permit Application under Part 49
Cottonwood Compressor Station (Title V Permit No# V-OU-00007-2004.00)

Dear Mr. Wortman:

Anadarko Uintah Midstream LLC (Anadarko) submitted, on September 20, 2013, a revised permit application for the Cottonwood Wash Compressor Station located in Uintah County, Utah to comply with Part 49 Minor NSR rules. On September 26, 2013, EPA had follow-up questions concerning:

1) Detailed flare specifications for the produced water tanks
2) Supporting data for the 13 bbl/day condensate throughput estimate
3) Clarification of the Confidential Business Information "CBI" claim

Please find supporting documentation for (1) as Appendix A and (2) as Appendix B.

In regards to (3), Anadarko is hereby submitting the following statement:

> " It was not Anadarko's intent to submit the revised permit application, dated September 19, 2013, under CBI. The application simply included the July 12, 2006 document that was stamped "CBI", which is just circumstance of that historical document. Anadarko hereby retracts the status of the application as being "CBI" and amends it to "normal" processing status."

If you have any questions, or require additional information, please contact me at (720) 929-6511 or Katherine.Doolittle@anadarko.com.

Sincerely,

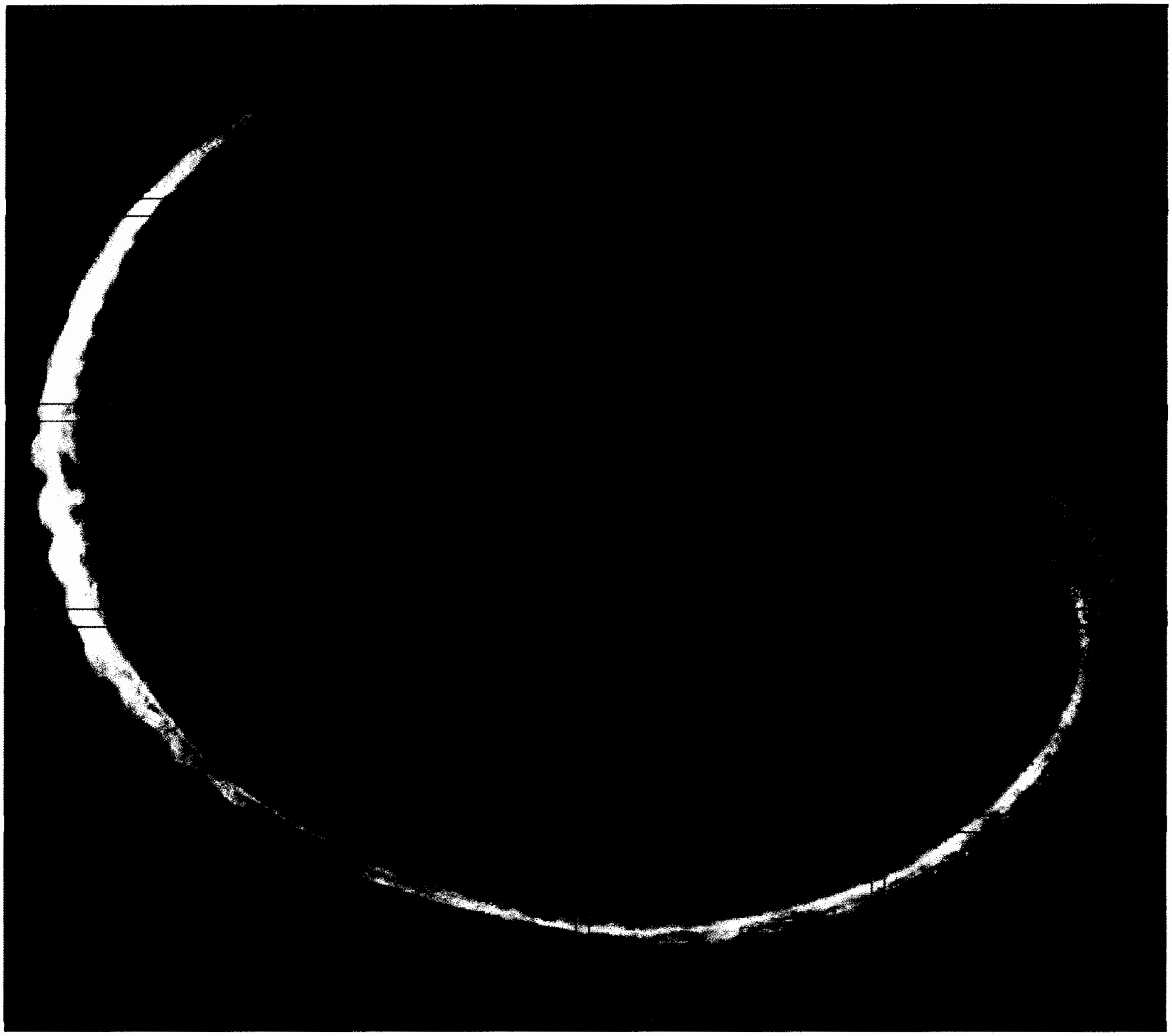
Anadarko Uintah Midstream LLC

Katherine Doolittle

Katherine Doolittle
Staff HSE Representative

Enclosures

A



Consent Decree Compliance Evaluation

Flare King, Inc. Model FKAVP-H25-R2S-EPTK Flare

July 2014

Prepares for:
Anadarko Petroleum Corporation
1099 18th St. #1800
Denver, CO 80202

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Consent Decree

Compliance Evaluation

for

Flare King, Inc. Model FKAVP-H25-R2S-EPTK Flare

Located at

Kerr-McGee Cottonwood Wash Compressor Station

July 2014

Table of Contents

List of Appendices

1.0 Control Device Equipment Description

The device evaluated is a Flare King assisted air flare designed to achieve 95% or greater VOC emissions reductions from condensate storage tanks

Manufacturer:	Flare King, Inc.
Model:	FKAVP-H25-R2S-EPTK
Description:	2" Air Assisted Variable Port Tip
	with Retractable 25' OAH Guyed Stack (non-enclosed)
Destruction Efficiency:	98%

2.0 Design Requirements

Paragraph 13 requires flare design and operation in compliance with 40 CFR 60.18(c)-(e).

40 CFR 60.18(c)	Flare Visible Emissions
40 CFR 60.18(d)	Flare Monitoring According to Design
40 CFR 60.18(e)	Flare Continuous Operation

2.1 40 CFR 60.18(c)

2.1.1 40 CFR 60.18(c)(1)

This section states that "Flares should be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours."

Section (f)(1) of paragraph (f) of this section applies to visible emissions from flares and requires Method 22, Visual determination of fugitive emissions from material sources and smoke emissions from flares, be used to determine visible emissions.

Flare is designed for smokeless operation through the incorporation of an air assisted flare tip, which allows high velocity assisted primary air to be injected to the waste gas flame. (See Appendix I).

Compliance with this requirement is satisfied and further explained in sections related to paragraph (c), below.

2.1.2 40 CFR 60.18(c)(2)

This section states that "Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f)."

Section (f)(2) of paragraph (f)of this section applies to flare pilot flame presence and requires that the presence of a pilot flame be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

Flare pilot assembly includes a stack mounted Fisher pressure regulator to ensure a steady supply of fuel gas for the pilot. The pilot fuel line is Teflon with stainless steel braided cover.

Flare is installed with an AC Auto Controller with a control box module and a booster box module. The control box module incorporates a thermocouple to determine the presence of a flame, and the booster box module manages an auto-ignition device that will reignite the pilot flame if it goes out.

The thermocouple is a J or K type and is located near the pilot inside a stainless steel sheath. A digital temperature controller connected to the thermocouple has an adjustable set point to alarm a "pilot out" status, which can be tied into audible, visual, or other safety alarm systems. The controller is equipped with an amber stroke light which flashes in the event of cycle failure.

The booster box module contains a 35,000 volt booster transformer which is routed to a spark plug via a stainless steel rod to enable automatic re-ignition.

Compliance with this requirement is satisfied.

2.1.3 40 CFR 60.18(c)(3)

This section states that, "An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4)[1] of this paragraph, or adhering to the requirements in paragraph (c)(3)(i) of this section."

(See 2.1.3.1 below for the applicability of the two methods and which is required for this flare)

[1] Assumed to also allow (c)(5) for air-assisted flares

2.1.3.1 40 CFR 60.18 (c)(3)(i)

40 C.F.R. 60.18(c)(3)(i)(A) states, "Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation."

This section applies to nonassisted flares only.

Compliance with this section is not required.

2.1.3.2 40 CFR 60.18 (c)(3)(ii)

This section states that, "Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section."

This is an air-assisted flare; and therefore, must have a net heating value of 11.2 MJ/scm (300 Btu/scf) or greater.

The method outlined in (f)(3) to calculate the net heating value of the combusted gas is as follows:

$$\mathrm{HT} = K * \sum_{f=1}^{n} CiHi$$

where:

H_T= Net heating value of the sample, MJ/scm; where the net enthalpy per mole of off gas is based on combustion at 25°C and 760 mmHg, but the standard temperature for determining the volume corresponding to one mole is 20°C;

K=$1.740 \times 10^{-7} \frac{1}{ppm} \frac{g\ mole}{scm} \frac{MJ}{kcal}$ where the standard temperature for $\frac{g\ mole}{scm}$ is 20°C

C_i= Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in 60.17); and

H_i= Net heat of combustion of sample component i, kcal/g mole at is 25°C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or D4809-95 (incorporated by reference as specified in 60.17) if published values are not available or cannot be calculated.

The gas being combusted in the flare will be gas formed from the flashing of condensate as the condensate stabilizes to atmospheric conditions. A representative sample of this pressurized condensate was taken from the White River Compressor Station.

The condensate sample used from the White River Compressor Station is representative of the condensate being dumped to the tanks from the slug catcher at the Cottonwood Compressor Station. Both stations receive gas from wells producing from the same formations. Operating pressures of the slug catchers at both stations range between 60-80 psig during normal operations. Attached are gas samples from the each facility after the liquids have been removed in the slug catcher and compressor dumps (See Appendix II). As shown, the samples are very similar in composition and heat content, which further supports that the condensate sample from the White River Station is representative of the condensate being dumped to the Cottonwood tanks.

Analysis of the condensate was performed in accordance with GPA 2186 (See Appendix III for these results).

This condensate sample demonstrated that there are few non-combustibles in the condensate. The combustibles present in the sample all have known net heat contents greater than 300 Btu/scf and the only component found in the condensate with a net heat content less than 300 Btu/scf is CO_2, which represents a small fraction of the total mole percent (1.142). Because of this it can be concluded that the overall net heat content of the gas created from the flashing of the condensate would be above the required 300 Btu/scf value set forth within this section.

To support the position of compliance stated above, the mole percent values form this condensate sample were incorporated into an E&P Tank 2.0 model and the representative flash gas composition, on a mole percent basis, was determined (See Appendix III for the results of this model).

The known net heating values for the individual components of the gas were then multiplied by the mole percent provided by the model (to represent the calculation set forth in (f)(3)) and the total net heating value of the sample was determined to be 1,458.44 Btu/scf.

This modeled net heating value of 1,458.44 Btu/scf for the gas to be combusted in the flare is well above the 300 Btu/scf minimum; therefore, compliance with this requirement is satisfied.

2.1.4 40 CFR 60.18(c)(4)

This section sets forth exit velocity specifications for steam-assisted and nonassisted flares.

Compliance with this section is not required.

2.1.5 40 CFR 60.18 (c)(5)

This section sets forth exit velocity specifications for air-assisted flares and states, "Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6)."

Paragraph (f)(6) provides the maximum permitted velocity, V_{max} as:

V_{max}=8.706+0.7084(H_T)

Where:

V_{max}= maximum permitted velocity, m/sec

8.706= constant

0.7084= constant

H_T= The net heating value as determined in paragraph (f)(3)

With the value H_T= 1,458.44 Btu/scf (54.45 MJ/scm) as stated in paragraph (f)(3) the maximum permitted velocity for this flare is:

V_{max}=8.706+0.7084(54.45)= 47.28 m/sec

Section (f)(4) of paragraph (f)of this section applies to flare actual exit velocity. According to this section, "The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip."

$V_{max,\ actual}$=(Volumetric flowrate)/(Cross sectional area of tip)

The design volumetric flowrate provided by the manufacturer is 0.015 MMscf/d with the diameter of the flare tip being 2 inches (radius of 1 inch).

Area of Tip= (π)(1/12)^2= 0.022 ft^2

$$Volumetric\ Flowrate = \frac{0.015 MMscf}{day} * \frac{Day}{24\ hrs} * \frac{hr}{60\ min} * \frac{min}{60\ sec} * \frac{1E6\ scf}{MMscf} = 0.174\ scf/sec$$

$V_{max,\ actual}$=(0.174 scf/s)/(0.022ft^2)=7.960 ft/s=2.426 m/s

The calculated actual exit velocity of 2.426 m/s is less than the maximum permitted velocity of 47.28 m/sec (per 60.18(d)); therefore, compliance with this requirement is satisfied.

2.1.6 40 CFR 10.18 (c)(6)

This paragraph states that, "Flares used to comply with this section shall be steam-assisted, air assisted, or nonassisted."

The flare is air assisted (See Appendix I); therefore, compliance with this requirement is satisfied.

2.2 40 CFR 60.18(d)

This paragraph states that, "Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices."

See Appendix I for a list of routine maintenance requirements for the pilot and flame arrestor per the manufacturer.

Compliance with all applicable subparts ensures compliance with these monitoring requirements; therefore, compliance with this section is satisfied.

2.3 40 CFR 60.18(e)

This paragraph states that, "Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them."

Kerr- McGee intends to operate the flare whenever emissions are vented to it and will report any times in which the gas going to the flare was bypassed and the duration of the event per Section XII (Reporting Requirements). This process will be facilitated through weekly inspections of each flare and documenting times of bypassing.

3.0 VOC Reduction Efficiency

Paragraph 13 requires flare operation in compliance manufacturer's written instructions or procedures to ensure compliance with 95% reduction efficiency stated in Paragraph 12.

Flare King provides operational and maintenance specifications/procedures for this flare (see Appendix I). This flare is designed to achieve a destruction efficiency of 98%.

Minimized downtime and adherence to these procedures, should ensure the flare is operated and maintained as designed, with 95% overall reduction efficiency; therefore, compliance with this requirement is satisfied.

4.0 Design Calculation Worksheet

Paragraph 13 requires a design calculation worksheet showing heat content determination, exit velocity determination, and flow rate estimates. A design calculation workbook is included as Appendix IV.

Appendix I

Excerpts from Flare King Specifications

Flare Type- Air Assisted

FLARE KING

AIR-ASSISTED

VARIABLE PORT FLARE TIP

ENGINEERING STATEMENT

The Flare King FKAVP flare is a proven design in providing smokeless combustion for a wide range of applications. Optimum efficiency is achieved by precise engineering, which produces predictable results to address concerns over smoke, flame instability, and other issues. High velocity assisted air is injected to the waste gas flame to provide primary air for clean smokeless combustion. An air-assisted tip is essential for smokeless operation in situation where the gases are heavy hydrocarbon waste gases.

The most outstanding features of the FKAVP flare are:

Smokeless operation of the highly engineered tip

An exclusive (patented) "bonnet" greatly increases the amount of air to the combustion process by drafting additional air into the flame area

A precisely engineered Variable-Port tip breaks up the "column" of exiting waste gas into multiple streams and introduces the waste gases "proportionally" into the surround air

An exclusive flame retention device of "flame retainer" prevents lift-off of the flare flame

An exclusive "retractable continuous pilot" provides automatic ignition and ease of maintenance at ground level

High combustion efficiency in heavy hydrocarbon compositions

No materials stress since the tip and air nozzle are designed for free expansions and contractions

High quality stainless steel construction for extended tip life

Routine Maintenance Requirements

Page 1

MAINTENANCE

The FKAVP Flare System is designed to require a minimum of routine maintenance. However a few components will need scheduled inspections and adjustments. They are:

1. FKAVP (Pilot)

   A. Once per month
      1. Check gas orifice for accumulated dirt and pipe scale
         a. Clean orifice with #70 twist drill bit by manually inserting into orifice and "plunging" a few times
         b. Blow clear with compressed air
      2. Check sparkplug for wear and gap
         a. Clean off excessive corrosion with wire b-rush
         b. Reset gap to .065"

   B. Every six (6) months
      1. Check for connection tightness on sparkplug
         a. Clean off any corrosion or carbon with wire brush or sandpaper
         b. Adjust rod so to prevent possible grounding
         c. Retighten connection if required
      2. Check pilot nozzle for burn out or deformation
      3. Control Panel
         a. Once per week
            1. Check light for burned out bulb
            2. Check general functions
         b. Once every three (3) months
            1. Check calibrations and timer settings
            2. Check for continuity
            3. Inspect wiring connections, and modules
            4. Check seals on enclosure box

2. Flame Arrestor

   A. Once per month
      1. Check for trapped liquid in housing, drain of necessary
      2. Check for any cell blockage and blow clean with compressed air

   B. Once every six (6) months
      1. Remove flame arrestor and check for heat affects on downstream side of element
      2. Perform general inspection of housing for corrosion, weld integrity, etc.

Appendix II

Gas Samples

Monthly Meter Analysis

July, 2014

Anadarko, Kerr McGee Gath, Western Gas Partners

Meter #: 0177653356
Name: WHITE RIVER M.P.
NAT_BUTTES

Sample			
Date: 05/02/2014			
Type: Spot			
Pressure:	253.0	H2O:	55.00lbs/mm
Temperature:	101.0	H2S:	0 ppm

Component	Mole %	Liquid Content	Mass %
Carbon Dioxide, CO2	0.8480		2.0233
Nitrogen, N2	0.1771		0.2690
Methane, C1	90.5158		78.7232
Ethane, C2	4.7671	1.2750	7.7711
Propane, C3	1.9699	0.5428	4.7092
Isobutane, iC4	0.3949	0.1292	1.2443
n-Butane, nC4	0.5375	0.1695	1.6937
Isopentane, iC5	0.2009	0.0735	0.7858
n-Pentane, nC5	0.1703	0.0617	0.6661
Hexanes Plus, C6+	0.4185	0.1826	2.1143
Water, H2O			
Hydrogen Sulfide, H2S			
Oxygen, O2			
Carbon Monoxide, CO			
Hydrogen, H2			
Helium, He			
Argon, Ar			
Totals	100.0000	2.4343	100.0000

Property	Total Sample
Pressure Base	14.730
Temperature Base	60.00
Relative Density	0.6383
HV, Dry @ Base P,T	1120.38
HV, Sat @ Base P, T	1100.89
HV, Sat @ Sample P, T	1116.25
Fws Factor	
Cricondentherm	75.770
HCDP @ Sample Pressure	65.450
Free Water GPM	
Stock Tank Condensate Brls/mm	
26 # RVP Gasoline	0.493
Testcar Permian	0.621
Testcar Panhandle	0.539
Testcar Midcon	0.608

*** End of Report ***

Monthly Meter Analysis

July, 2014

Anadarko, Kerr McGee Gath, Western Gas Partners

Meter #: 0018653607	
Name: COTTONWOOD DISCHARGE	
NAT_BUTTES	

Sample			
Date: 04/16/2014			
Type: Spot			
Pressure:	938.0	H2O:	lbs/mm
Temperature:	84.0	H2S:	ppm

Component	Mole %	Liquid Content	Mass %
Carbon Dioxide, CO2	0.9435		2.2553
Nitrogen, N2	0.1326		0.2018
Methane, C1	90.3682		78.7428
Ethane, C2	5.1531	1.3782	8.4161
Propane, C3	1.8390	0.5067	4.4045
Isobutane, iC4	0.3623	0.1186	1.1438
n-Butane, nC4	0.4555	0.1436	1.4380
Isopentane, iC5	0.1785	0.0653	0.6995
n-Pentane, nC5	0.1516	0.0550	0.5941
Hexanes Plus, C6+	0.4157	0.1814	2.1041
Water, H2O			
Hydrogen Sulfide, H2S			
Oxygen, O2			
Carbon Monoxide, CO			
Hydrogen, H2			
Helium, He			
Argon, Ar			
Totals	100.0000	2.4488	100.0000

Property	Total Sample
Pressure Base	14.730
Temperature Base	60.00
Relative Density	0.6371
HV, Dry @ Base P,T	1116.87
HV, Sat @ Base P, T	1097.44
HV, Sat @ Sample P, T	1116.20
Fws Factor	
Cricondentherm	74.446
HCDP @ Sample Pressure	66.807
Free Water GPM	
Stock Tank Condensate Brls/mm	
26 # RVP Gasoline	0.471
Testcar Permian	0.499
Testcar Panhandle	0.514
Testcar Midcon	0.542

*** End of Report ***

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Print Date: 07/23/2014 14:22 Page 1

Appendix III

E&P Tank 2.0 Model Inputs and Results

Condensate Sample- Input into E&P Tank 2.0 Model

AMERICAN MOBILE RESEARCH, INC.
P.O. BOX 2909
CASPER, WYOMING 82602
(307) 235-4590 PHONE
(307) 265-4489 FAX

EXTENDED HYDROCARBON (GLYCALC) LIQUID STUDY
CERTIFICATE OF ANALYSIS

Company .... **ANADARKO PETROLEUM CORPORATION**
Lab Number CR-12160
Date Sampled 2-29-2012
Study Number CR-1
Date Tested 3-9-2012

Sample Identification .... **WHITE RIVER CONDENSATE**

Sample Location .... NATURAL BUTTES FIELD, VERNAL, UTAH.
Sample Pressure .... 95 PSIG
Type Sample .... SPOT
Test Method .... GPA 2186
Sample Temperature .... N/A
County .... UINTAH
Sampling Method GPA-2174

Components	Mole %	Weight %	Liq. Vol. %
Hydrogen Sulfide	0.000	0.000	0.000
Oxygen	0.000	0.000	0.000
Carbon Dioxide	0.045	0.019	0.016
Nitrogen	0.000	0.000	0.000
Methane	1.997	0.305	0.711
Ethane	0.791	0.226	0.444
Propane	1.166	0.489	0.674
iso-Butane	0.795	0.440	0.546
n-Butane	1.710	0.946	1.131
iso-Pentane	1.818	1.248	1.395
n-Pentane	2.147	1.474	1.633
Hexanes	3.406	2.792	2.940
Heptanes	21.130	20.142	20.460
Octanes	38.967	42.345	41.897
Nonanes	12.437	15.175	14.688
Decanes+	4.212	6.106	5.760
Benzene......................	0.895	0.665	0.525
Toluene.......................	1.327	1.163	0.932
Ethylbenzene..............	0.062	0.063	0.050
Xylenes.......................	2.028	2.048	1.653
n-Hexane	4.314	3.537	3.723
2,2,4-Trimethylpentane.	0.753	0.818	0.821
Totals.........................	100.000	100.000	100.000

ADDITIONAL BETX DATA

Flash Emissions- Modeled in E&P Tank 2.0

Component	Mole % of Flash Gas [1]	Gross Heating Value @ 60 °F (Btu/ft3) Ideal gas	Gross Heating Value per Component (Btu/ft3)	Net Heating Value @ 60 °F (Btu/ft3) Ideal gas	Net Heating Value per Component (Btu/ft3)
H2S	0.000	637.1	0.00	586.8	0.00
O2	0.000	0	0.00	0	0.00
CO2	1.142	0	0.00	0	0.00
N2	0.000	0	0.00	0	0.00
C1	64.942	1010	655.91	909.4	590.58
C2	13.804	1769.7	244.28	1618.7	223.44
C3	7.908	2516.1	198.98	2314.9	183.07
i-C4	2.271	3251.9	73.86	3000.4	68.15
n-C4	3.424	3262.3	111.70	3010.8	103.09
i-C5	1.410	4000.9	56.43	3699	52.17
n-C5	1.213	4008.7	48.63	3706.9	44.97
C6	0.703	4755.9	33.43	4403.8	30.96
C7	1.391	5502.6	76.54	5100	70.94
C8	0.773	6249	48.30	5796	44.80
C9	0.082	6996.3	5.70	6493.2	5.29
C10+	0.006	0	0.00	7189.5	0.44
Benzene	0.132	3591.1	4.73	3590.9	4.73
Toluene	0.052	4273.7	2.23	4273.7	2.23
E-Benzene	0.001	4970.7	0.04	4970.4	0.04
Xylenes	0.022	4957.3	1.07	4956.1	1.07
n-C6	0.686	4755.9	32.62	4403.8	30.20
224 Trimethylpentane	0.039	5779.1	2.27	5796	2.28
Sum	100.00		**1596.72**		**1458.44**
				1358.128506	

[1] Flash gas composition determined by running liquids analysis through E&P Tank v2.0 model and flashing to atmospheric conditions

Appendix IV

Design Calculation Worksheet

Net Heating Value

Pursuant to Section f(3):
Net Heating Value= Σ(Component Sample Cocentration*Net Heat of Combustion of Component)

Component	Mole % of Flash Gas [1]	Net Heating Value @ 60 °F (Btu/ft3) Ideal gas	Net Heating Value per Component (Btu/ft3)
H2S	0.000	586.8	0.00
O2	0.000	0	0.00
CO2	1.142	0	0.00
N2	0.000	0	0.00
C1	64.942	909.4	590.58
C2	13.804	1618.7	223.44
C3	7.908	2314.9	183.07
i-C4	2.271	3000.4	68.15
n-C4	3.424	3010.8	103.09
i-C5	1.410	3699	52.17
n-C5	1.213	3706.9	44.97
C6	0.703	4403.8	30.96
C7	1.391	5100	70.94
C8	0.773	5796	44.80
C9	0.082	6493.2	5.29
C10+	0.006	7189.5	0.44
Benzene	0.132	3590.9	4.73
Toluene	0.052	4273.7	2.23
E-Benzene	0.001	4970.4	0.04
Xylenes	0.022	4956.1	1.07
n-C6	0.686	4403.8	30.20
224 Trimethylpentane	0.039	5796	2.28
Sum	100.00		**1,458.44**

Net Heating Value=	1458.44	Btu/scf

Maximum Permitted Exit Velocity

Pursuant to Section f(6):

Vmax= 8.706+0.7084(HT)

Where:

HT=	1,458.44	Btu/scf
	54.45	MJ/.scm

Vmax=	8.706+0.7084(54.45)	m/sec
Vmax=	47.28	m/sec

Acutal Exit Velocity

Pursuant to Section f(4):
Actual Exit Velocity= Volumetric flowrate/Area of the tip

Diameter of Tip=	2	in.
Radius of Tip=	1	in.
Radius of Tip=	(1/12)	ft
Radius of Tip=	0.083333333	ft
Area of Tip=	π*R^2	
Area of Tip=	π*0.08333^2	ft^2
Area of Tip=	0.022	ft^2
Flow Rate=	0.015	MMscf/D

$$Flow\ Rate = \frac{0.015 MMscf}{Day} * \frac{Day}{24\ hrs} * \frac{hr}{60\ min} * \frac{min}{60\ sec} * \frac{1E6\ scf}{MMscf}$$

Flow Rate=	0.174	scfs	
Actual Exit Velocity=	(0.174 scf/s)/(0.022ft^2)		
Actual Exit Velocity=	7.960	ft/s	at standard condtions
Actual Exit Velocity=	$\boxed{2.426}$	m/s	at standard condtions

B

Cottonwood/West Compressor Station

Condensate		Production	Average Production
Year	Month	bbls/month	bbls/day
2012	May	495	16
	Jun	400	13
	Jul	0	0
	Aug	315	10
	Sep	500	17
	Oct	480	15
	Nov	570	19
	Dec	380	12
2013	Jan	820	26
	Feb	375	13
	Mar	320	10
	Apr	0	0
	May	620	20
	Jun	380	13
	Jul	200	6
	Aug	415	13
	Average Daily Production		13

RECEIVED
SEP 20 2013
8P - AR

Anadarko Uintah Midstream LLC
P.O. Box 173779, Denver, Colorado80217-3779
720-929-6000 Fax 720-929-7000

September 19, 2013

SENT VIA CERTIFIED MAIL No.: 91 7199 9991 7032 7523 2304

Mr. Eric Wortman
U.S. EPA, Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129

**RE: Revised Synthetic Minor NSR Permit Application under Part 49
Cottonwood Compressor Station (Title V Permit No# V-OU-00007-2004.00)**

Dear Mr. Wortman:

Anadarko Uintah Midstream LLC (Anadarko) submitted on August 30, 2012 a permit application under newly promulgated Part 49 Minor NSR rules for the Cottonwood Wash Compressor Station located in Uintah County, Utah. The application has been updated. Therefore, Anadarko Uintah Midstream LLC is submitting the revised application to reflect these changes. Please replace previously submitted information with this application.

If you have any questions, or require additional information, please call me at (720) 929-6867 or via email at Chad.Schlichtemeier@Anadarko.com

Sincerely,

Anadarko Uintah Midstream LLC

Chad Schlichtemeier

Chad Schlichtemeier
EHS Air Manager

Enclosures

OMB Control No. 2060-0003
Approval expires 04/30/2012

United States Environmental Protection Agency Program Address Phone Fax Web address	*Reviewing Authority* *Program* *Address* *Phone* *Fax* *Web address*

FEDERAL MINOR NEW SOURCE REVIEW PROGRAM IN INDIAN COUNTRY

Application for New Construction

(Form NEW)

Please check all that apply to show how you are using this form:

☐ **Proposed Construction of a New Source**
☐ **Proposed Construction of New Equipment at an Existing Source**
☐ **Proposed Modification of an Existing Source**
☒ **Other – Please Explain**

Existing Source operating under synthetic minor limits submitting an application for a synthetic minor permit under Part 49.

Please submit information to:

[Reviewing Authority
Address
Phone]

A. GENERAL SOURCE INFORMATION

1. (a) **Company Name** Anadarko Uintah Midstream LLC (b) **Operator Name** Anadarko Uintah Midstream LLC		2. **Source Name** Cottonwood Wash Compressor Station	
3. Type of Operation Nat.Gas Compression & Transmission		4. Portable Source? ☐ Yes ☐ No 5. Temporary Source? ☐ Yes ☐ No	
6. NAICS Code		7. SIC Code 1311	
8. Physical Address (home base for portable sources)			
9. Reservation* Uintah and Ouray	10. County* Uintah	11a. Latitude* 40° 0'35" N	11b. Longitude* 109° 32'38" W
12a. Quarter Quarter Section*	12b. Section* 27	12c. Township* 9S	12d. Range* 21E

*Provide all proposed locations of operation for portable sources

B. PREVIOUS PERMIT ACTIONS (Provide information in this format for each permit that has been issued to this source. Provide as an attachment if additional space is necessary)

Source Name on the Permit
Permit Number (xx-xxx-xxxxx-xxxx.xx)
Date of the Permit Action

Source Name on the Permit
Permit Number (xx-xxx-xxxxx-xxxx.xx)
Date of the Permit Action

Source Name on the Permit
Permit Number (xx-xxx-xxxxx-xxxx.xx)
Date of the Permit Action

Source Name on the Permit
Permit Number (xx-xxx-xxxxx-xxxx.xx)
Date of the Permit Action

Source Name on the Permit
Permit Number (xx-xxx-xxxxx-xxxx.xx)
Date of the Permit Action

C. CONTACT INFORMATION

Company Contact Brent Naherny	Title Midstream Operations Manager
Mailing Address P.O.Box 173779, Denver, CO 80202-3779	
Email Address Brent.Naherny@anadarko.com	
Telephone Number 720-929-6748	Facsimile Number
Operator Contact (if different from company contact) Clayton Rimer	Title Sr Maint. Foreman
Mailing Address	
Email Address Clayton.Rimer@anadarko.com	
Telephone Number 435-781-9728	Facsimile Number
Source Contact Katherine Doolittle	Title Sr EHS Representative
Mailing Address P.O.Box 173779, Denver, CO 80202-3779	
Email Address Katherine.Doolittle@Anadarko.com	
Telephone Number 720-929-6511	Facsimile Number 720-929-7867
Compliance Contact Same as Source Contact	Title
Mailing Address	
Email Address	
Telephone Number	Facsimile Number

D. ATTACHMENTS

Include all of the following information (see the attached instructions)

☒ **FORM SYNMIN** - New Source Review Synthetic Minor Limit Request Form, if synthetic minor limits are being requested.

☒ Narrative description of the proposed production processes. This description should follow the flow of the process flow diagram to be submitted with this application.

☒ Process flow chart identifying all proposed processing, combustion, handling, storage, and emission control equipment.

☒ A list and descriptions of all proposed emission units and air pollution-generating activities.

☒ Type and quantity of fuels, including sulfur content of fuels, proposed to be used on a daily, annual and maximum hourly basis.

☐ Type and quantity of raw materials used or final product produced proposed to be used on a daily, annual and maximum hourly basis.

☒ Proposed operating schedule, including number of hours per day, number of days per week and number of weeks per year.

☒ A list and description of all proposed emission controls, control efficiencies, emission limits, and monitoring for each emission unit and air pollution generating activity.

☒ **Criteria Pollutant Emissions** - Estimates of Current Actual Emissions, Current Allowable Emissions, Post-Change Uncontrolled Emissions, and Post-Change Allowable Emissions for the following air pollutants: particulate matter, PM_{10}, $PM_{2.5}$, sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compound (VOC), lead (Pb) and lead compounds, fluorides (gaseous and particulate), sulfuric acid mist (H_2SO_4), hydrogen sulfide (H_2S), total reduced sulfur (TRS) and reduced sulfur compounds, including all calculations for the estimates.

These estimates are to be made for each emission unit, emission generating activity, and the project/source in total.

☒ **Modeling – Air Quality Impact Analysis (AQIA)**

☐ **ESA (Endangered Species Act)**

☐ **NHPA (National Historic Preservation Act)**

E. TABLE OF ESTIMATED EMISSIONS

The following tables provide the total emissions in tons/year for all pollutants from the calculations required in Section D of this form, as appropriate for the use specified at the top of the form.

E(i) – Proposed New Source

Pollutant	Potential Emissions (tpy)	Proposed Allowable Emissions (tpy)
PM		3.8
PM_{10}		3.8
$PM_{2.5}$		3.8
SO_x		
NO_x		176.5
CO		232.0
VOC		124.6
~~Pb~~ CO2e		54307.7
Fluorides		
H_2SO_4		
H_2S		
TRS		
RSC		

PM - Particulate Matter
PM_{10} - Particulate Matter less than 10 microns in size
$PM_{2.5}$ - Particulate Matter less than 2.5 microns in size
SOx - Sulfur Oxides
NOx - Nitrogen Oxides
CO - Carbon Monoxide
VOC - Volatile Organic Compound
Pb - Lead and lead compounds
Fluorides - Gaseous and particulates
H_2SO_4 - Sulfuric Acid Mist
H_2S - Hydrogen Sulfide
TRS - Total Reduced Sulfur
RSC - Reduced Sulfur Compounds

Emissions calculations must include fugitive emissions if the source is one the following listed sources, pursuant to CAA Section 302(j):

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;
(t) Chemical process plants
(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(w) Taconite ore processing plants;
(x) Glass fiber processing plants;
(y) Charcoal production plants;
(z) Fossil fuel-fired steam electric plants of more that 250 million British thermal units per hour heat input, and
(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

OMB Control No. 2060-0003
Approval expires 04/30/2012

United States Environmental Protection Agency Program Address Phone Fax Web address	*Reviewing Authority* *Program* *Address* *Phone* *Fax* *Web address*

FEDERAL MINOR NEW SOURCE REVIEW PROGRAM IN INDIAN COUNTRY

Application For Synthetic Minor Limit
(Form SYNMIN)

Please submit information to:

[Reviewing Authority
Address
Phone]

A. GENERAL INFORMATION

Company Name Anadarko Uintah Midstream LLC	**Source Name** Cottonwood Wash Compressor Station
Company Contact or Owner Name Brent Naherny	Title Midstream Operations Manager
Mailing Address P.O.Box 173779, Denver, CO 80202-3779	
Email Address Brent.Naherny@anadarko.com	
Telephone Number 720-929-6748	Facsimile Number

B. ATTACHMENTS

For each criteria air pollutant, hazardous air pollutant and for all emission units and air pollutant-generating activities to be covered by a limitation, include the following:

☒ **Item 1** - The proposed limitation and a description of its effect on current actual, allowable and the potential to emit.

☒ **Item 2** - The proposed testing, monitoring, recordkeeping, and reporting requirements to be used to demonstrate and assure compliance with the proposed limitation.

☐

☒ **Item 3** - A description of estimated efficiency of air pollution control equipment under present or anticipated operating conditions, including documentation of the manufacturer specifications and guarantees.

☐

☒ **Item 4** - Estimates of the Post-Change Allowable Emissions that would result from compliance with the proposed limitation, including all calculations for the estimates.

☒ **Item 5** – Estimates of the potential emissions of Greenhouse Gas (GHG) pollutants:

E(ii) – Proposed New Construction at an Existing Source or Modification of an Existing Source

Pollutant	Current Actual Emissions (tpy)	Current Allowable Emissions (tpy)	Post-Change Potential Emissions (tpy)	Post-Change Allowable Emissions (tpy)
PM				
PM_{10}				
$PM_{2.5}$				
SO_x				
NO_x				
CO				
VOC				
Pb				
Fluorides				
H_2SO_4				
H_2S				
TRS				
RSC				

PM - Particulate Matter
PM_{10} - Particulate Matter less than 10 microns in size
$PM_{2.5}$ - Particulate Matter less than 2.5 microns in size
SOx - Sulfur Oxides
NOx - Nitrogen Oxides
CO - Carbon Monoxide
VOC - Volatile Organic Compound
Pb - Lead and lead compounds
Fluorides - Gaseous and particulates
H_2SO_4 - Sulfuric Acid Mist
H_2S - Hydrogen Sulfide
TRS - Total Reduced Sulfur
RSC - Reduced Sulfur Compounds

[Disclaimers] The public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response, unless a modeling analysis is required. If a modeling analysis is required, the public reporting and recordkeeping burden for this collection of information is estimated to average 60 hours per response .Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

Attachment B

CO Emissions:

- Uncontrolled CO emissions from the Caterpillar engines are over 250 tpy. Oxidation catalyst is required on the 4 stroke lean burn Caterpillar engines by NESHAP Subpart ZZZZ. Anadarko Uintah Midstream is requesting limits for CO.
    - Proposed limits
        - CO Emission Limits (Controlled)
            - Caterpillar 3500 series engines
                - 1.21 g/hp-hr
            - Caterpillar 3600 series engines
                - 1.63 g/hp-hr
    - Proposed testing
        - Initial testing:
            - New Engines
                - Initial compliance test shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.
            - Existing Engines
                - Initial compliance test shall be conducted within 180 days from the issuance date of the permit.
            - Test Methods:
                - Measure the O_2 and CO at the outlet of the control device using portable analyzer. Use ASTM D6522-00 (2005) or Method 10 of 40 CFR appendix A for CO. Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
                    - Convert to g/hp-hr using Method 19 and the manufacture's specific fuel consumption or measured fuel consumption and horsepower at the time of the testing.
                - Conduct three separate test runs for each performance test required. Each test run must last at least 1 hour
        - Periodic testing:
            - Perform subsequent performance tests semi-annually to verify compliance with g/hp-hr limits. After compliance is demonstrated for two consecutive tests, the testing frequency shall be reduced to annually if the total facility CO emissions are less than 150 tpy. Total facility CO emissions shall be calculated based on the results of the latest test and 8,760 hours per year of operation. Should the total facility emissions exceed this level, then semi-annual performance tests shall be resumed.
            - Test Methods:
                - Measure the O_2 and CO at the outlet of the control device using portable analyzer. Use ASTM D6522-00 (2005) or Method 10 of 40 CFR appendix A for CO. Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.

- Convert to g/hp-hr using Method 19 and the manufacture's specific fuel consumption or measured fuel consumption and horsepower at the time of the testing.
- Conduct one (1) test run for each performance test required. Each test run must last at least 21 minutes

- Operation and Maintenance Requirements
  - At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

- Reporting Requirements

  - Notification of performance test shall be submitted 30 days prior to the date of the performance test.
  - Test reports shall be submitted within 60 days of completion of any compliance test.

Formaldehyde Emissions:

- This facility is a major source of HAPs and is subject to the requirements of NESHAP Subpart ZZZZ. Limit the concentration of formaldehyde in the engine exhaust to 14 ppmvd or less at 15 percent O2 (if it is not complying with CO reduction limits in the rule). No further limits are being requested.

NOx Emissions:

- NOx emissions based off manufacture's information. For the 3500 series engines an emission factor of 2.0 g/hp-hr was used. Total facility emissions are below the PSD threshold and, therefore, no limits are being requested.

  - Caterpillar 3500 series engines
    - Manufacture's information 1.5 to 2.0 g/hp-hr
  - Caterpillar 3600 series engines
    - Manufacture's information 0.7 g/hp-hr

- Proposed testing

    - NOx testing will be conducted concurrently with CO testing required by this permit.

    - Test Methods:
      - Testing will be conducted using Method 7E or a portable analyzer with an approved protocol

  - Reporting Requirements

    - Test reports shall be submitted within 60 days of completion of any compliance test. Annual emission inventories will be used to verify NOx emissions do not exceed 250 tpy.

VOC Emissions:

- Caterpillar engines
  - Uncontrolled emissions are based on manufacture's information and no VOC emission reductions are being claimed from the controls of the engines. Since uncontrolled emissions are below the PSD threshold, no limits are being requested.

- Produced Water Tanks
  - In 2011, a new inlet slug catcher system was installed. Part of system was a blow case. The blow case takes condensate recovered in the slug catcher and sends it down the pipeline for processing. The slug catcher is currently not 100 percent effective in removing the condensate from the water. Anadarko continues to work on this issue, but the water tanks currently receive condensate carry over from the inlet slug catcher. The tanks are controlled by a flare. Emissions from the flare are based on condensate collected in the tanks from May 2012 to April 2013. Anadarko Uintah Midstream is requesting that the tank control (flare) be recognized in this permit. No throughput limit is requested because the blow case is part of the process equipment and is the primary means of handling condensate at this facility. With the requirement that the tanks are controlled by a flare, the emissions from the tanks will remain insignificant.
    - Proposed limits:
      - Emissions from the three (3) produced water tanks shall be routed to a flare
    - Proposed Testing
      - Weekly AVO inspections
        - Flare pilot lit? (Y/N)
        - Flare operating properly (e.g. vapors making it to the flare)? (Y/N)
        - Flare smokeless? (Y/N)
        - Thief hatches closed (Y/N)
        - Any leaks (e.g. thief hatches, vents). (Y/N)
      - Monthly FLIR Inspections
        - Tanks and closed-vent system
        - FLIR camera will be maintained and operated according to manufacturer's specifications
    - Recordkeeping
      - Results of inspections shall be recorded
        - Repairs shall be documented and completed as soon as practical
- Low-Emission Dehydrators.
  - Permit Limit:
    - All new and existing glycol dehydration units shall meet the following requirements.
      - "Low-Emission Dehydrator shall meet the specifications set forth in Appendix C (attached) and shall mean a dehydration unit that:
        - Incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function;
        - Either returns the captured vapors to the inlet of the facility where such dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and
        - Has a PTE less than 1.0 TPY of VOCs, inclusive of VOC emissions from the reboiler burner.

- Existing Units
  - Attached in the July 12, 2006 letter documenting the existing units meet the requirements above.
- Reporting
  - Written notification to EPA within 60 Days of each installation of a new Low-Emission Dehydrator, and include a description of the equipment installed and a certification that the Low-Emission Dehydrator meets the criteria set forth in this permit. The certification shall be signed by a Responsible Official or by a delegated employee representative, unless otherwise required by applicable statute or regulation. All reports and submissions shall include the following certification:

    > I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete.
- Recordkeeping
  - Shall maintain records and information adequate to demonstrate its compliance with the requirements of this permit, and shall report the status of its compliance annually

- Pneumatic Controllers
  - Permit Limit:
    - All pneumatic controllers shall be operated on instrument air

Low-Emission Dehydrator
Appendix C
July 12, 2006 letter

APPENDIX C

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

LOW-EMISSION DEHYDRATOR SPECIFICATIONS

Overview and Purpose

Kerr-McGee has agreed to employ "Low-Emission Dehydrator" technology at its existing and planned facilities in the Uinta Basin as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.A., this Appendix C includes:

(a) a description of physical electrical hard-wiring between the vapor recovery unit ("VRU") compressor(s) and the glycol circulation pumps employed or to be employed, so that if the VRU compressor(s) go down then the glycol circulation pump(s) also shut down, thereby halting the circulation of glycol through the wet gas, as well as the emissions associated with the regeneration of the glycol;

(b) a description of a second level of protection (redundancy) incorporated into a Programmable Logic Controller that uses instrumentation to shut down the glycol dehydration system in the event all VRU compressor(s) go down; and

(c) a description of any third level of protection and discussion of how the non-condensible gases from glycol dehydrator operation shall be piped exclusively to the station inlet or fuel system for use as fuel and is not used for blanket gas in storage tanks or otherwise vented.

Background

Natural gas often contains water vapor at the wellhead which must be removed to avoid pipeline corrosion and solid hydrate formation. Glycol dehydration is the most widely used natural gas dehumidification process. In a glycol dehydration system, dry triethylene glycol ("TEG") or ethylene glycol ("EG") is contacted with wet natural gas. The glycol absorbs water from the natural gas, but also absorbs hydrocarbons including volatile organic compounds ("VOCs") and certain hazardous air pollutants ("HAPs"). Pumps circulate the glycol from a low-pressure distillation column for regeneration back to high pressure in order to contact with the high pressure wet gas. As the wet glycol pressure is reduced prior to distillation, much of the absorbed hydrocarbon is released, including some of the VOCs and HAPs. A flash tank is typically utilized to separate these vapors at a pressure where they can be utilized for fuel. Distillation removes the absorbed water along with any remaining hydrocarbon, including VOCs and HAPs, from the glycol to the still column vent as overhead vapor. Conventional dehydrator still columns often emit the non-condensable portion of this overhead vapor directly to the atmosphere, or to a combustion device such as a thermal oxidizer or reboiler burner.

Kerr-McGee currently utilizes low-emission glycol dehydrators at its facilities in the Uinta Basin. These units capture the non-condensable portion of still vent and flash tank vapors and recompress the vapor with reciprocating or scroll compressors that route the

vapor to the station inlet as natural gas product, to fuel lines for power generation turbines or to the station fuel system. They also employ electric glycol circulation pumps, and except for the recompression of non-condensable vapors, resemble conventional glycol dehydrators in their configuration. See Figure 1.

To insure that the non-condensable vapor compression system is fully integrated into dehydrator operation such that the units cannot be disabled so as to operate while venting to the atmosphere, each unit;

a. incorporates an integral vapor recovery function that prevents the dehydrator from operating independent of the vapor recovery function;
b. either returns the captured vapors to the inlet of the facility where each glycol dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and
c. thereby emits no more than 1.0 ton per year of VOCs.

Description of Interlocks

The low-emission glycol dehydrators have at least three (3) levels of protection to prevent emissions from occurring.

(a) Physical electrical hard-wiring between the vapor recovery unit (VRU) compressor(s) and the glycol circulation pumps ensures that if the VRU compressor(s) goes down, the glycol pump(s) also shut down, thereby halting the circulation of glycol through the wet gas as well as the emissions associated with the regeneration of glycol. More specifically:

1. Loss of station power interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor.
2. Loss of 24 volt power to a relay interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor. The 24 volt power is wired in parallel through the run status contacts of each VRU compressor in a specific service. If all VRU compressors in each specific service are shutdown, the 24 volt power is interrupted. There is at least one spare VRU compressor in standby mode for each specific service at existing Uinta Basin facilities engaged in gas dehydration. Non-condensable gas from VRU compressor discharge always has an outlet because if the station inlet pressure rises to a level greater than VRU compressor output, the flash tank vapors automatically go through a back pressure regulator to the fuel gas system until gathering pressure is reduced.
3. If the glycol still column/reboiler pressure rises above pressure set points, the 24 volt power to a relay is interrupted. The unpowered relay interrupts the 480 volt power to the glycol pump(s) circulating glycol to the contactor. If one of the glycol still VRU compressors is running but not compressing vapors, the pressure switch will detect the pressure rise in the still and shutdown the glycol circulating pump(s).

4. The operation of at least one of the VRU compressors is required to complete the electrical circuit and allow one of the glycol circulation pumps to operate.
5. There is a 10 second time delay switch installed in the physical electrical circuit that must time out before the glycol circulating pump(s) shut down for causes 2 and 3 above. This allows for switching of compressors and helps to prevent false shutdowns.
6. Everything is hard wired and does not depend on any type of controller.

(b) A second level of protection redundancy has been incorporated by utilizing the station Programmable Logic Controller (PLC) to shut down the dehydration system in the event the VRU compressor(s) go down.

1. A PLC timer will start counting when none of the VRU compressor(s) are in operation. When the timer times out, the PLC will not allow the regenerator system to be in run status.

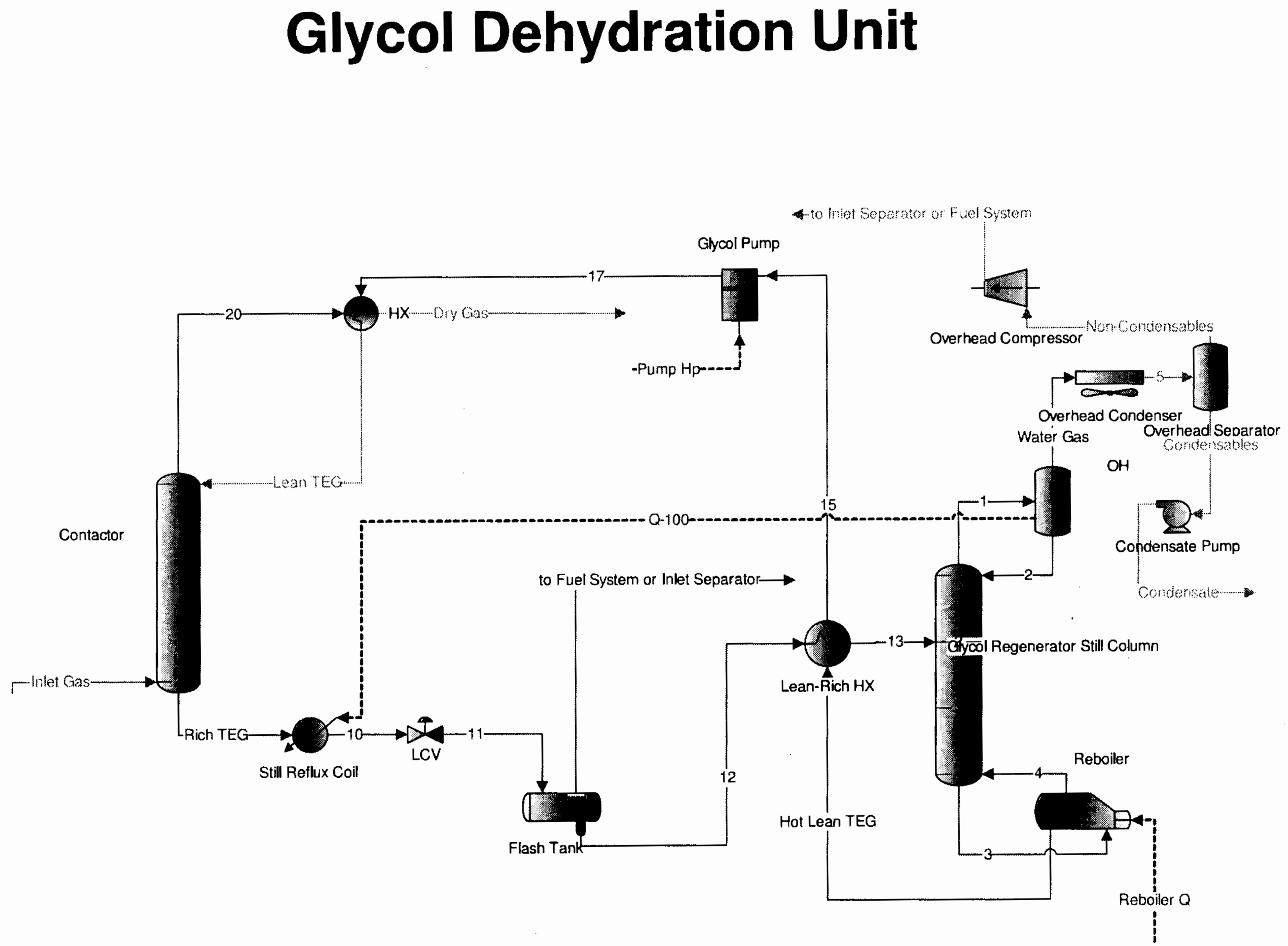
(c) A third level of protection is the routing of non-condensables directly to combustion devices in the stations that utilize micro-turbine electrical generators or central heat medium systems.

1. The non-condensable regenerator overhead vapors are routed to the inlet of each station or used as fuel. In instances where the inlet pressure rises above VRU compressor outlet pressures, a regulator opens allowing the VRU-compressed vapors to be discharged into the fuel system, where they are used throughout the station.
2. In Kerr-McGee's planned electrified compressor stations, liquids that condense at the compression stations, including those condensed from the glycol still overhead vapors, will be contained at pressure, separated from any water and pumped downstream into the high pressure gathering system. This process change will eliminate atmospheric storage of hydrocarbon liquids at such facilities.

Conclusion

Kerr-McGee's adherence to these specifications shall satisfy its commitment in the Consent Decree to utilize low-emission dehydrator technology in its existing and planned Uinta Basin operations.

Figure 1: Kerr-McGee Low-Emission Dehydrator Schematic



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KerrMcGee

July 12, 2006

Kerr-McGee Oil & Gas OnShore LP
1999 Broadway, Suite 3700, Denver, Colorado 80202
303-296-3600 • Fax 303-296-3601

Ms. Kathleen Paser
Environmental Engineer
U.S. EPA
Air and Radiation Program (8P-AR)
999 18th Street, Ste. 300
Denver, CO 80202

CONFIDENTIAL BUSINESS INFORMATION

Re: Independent Engineering Evaluation
Ouray Dehydration Unit
Cottonwood Dehydration Unit
Bridge Station Dehydration Unit

Dear Ms. Paser,

Attached for your information are independent engineering evaluations conducted by Huzyk Energy Management Inc. for the three named dehydration units located in Uintah County, Utah. The purpose of the evaluations was to determine what emissions if any are associated with the operation of these new types of dehydration units. As you know, this evaluation is intended to support EPA's final issuance of Part 71 operating permits for the facilities at which these units are located.

Sandra Huzyk's analysis confirmed that our dehydrators have zero emissions of VOC's from the routing of regenerator and flash tank overheads to integrated vapor recovery units (VRU's), and that safeguards exist to ensure that the dehydrator shuts down if the VRU's are shut down for any reason. I have included a copy of Ms. Huzyk's background and qualifications at the end of the report.

If you have any questions please feel free to contact me at 720-264-2717.

Very truly yours,

Ed G. Schicktanz

Ed G. Schicktanz
Senior Staff Environmental Specialist
Kerr-McGee Oil and Gas Onshore LP

HUZYK ENERGY MANAGEMENT, INC.

Chemical Engineering and Project Management

Sandra L. Huzyk, P. E.

Mr. Ed Schicktanz
Sr. Staff Environmental Specialist
Kerr-McGee Oil & Gas Onshore, LP
1999 Broadway
Suite 3700
Denver, CO 80202

CONFIDENTIAL BUSINESS INFORMATION

May 26, 2006

Cottonwood Plant Dehydration Evaluation
Uintah County, Utah

Summary
I spent a couple of hours at the site observing operation of the TEG dehydration plant, questioning Mr. Gary Brom, facility engineer; and observing a test. I have concluded Cottonwood has zero-emission operation under normal conditions.

Discussion

Operation of Gas Dehydration

The attached flowsheets and mass balance provide operation and equipment detail for the discussion that follows. In each 'Inlets and Outlets' table the third entry (under temperature and pressure) is the total mass flow rate, which will provide an accurate overall mass balance. Below this entry, I have included component flow rates for VOC. You may use this to track a component mass balance for each VOC brought in with the gas. The 'Liquid Circulation' table shows BTEX absorption into the solvent, and residual values after regeneration. This table is not involved in computing the overall mass balance.

Natural gas flows from the gathering systems into inlet separation and compression. Approximately 40 mmscfd of compressed gas at 545 psig flows to the TEG contactor. It enters the contactor at the bottom, flowing upwards against downward flow of the solvent, triethylene glycol. Gas and liquid contact on the absorber trays allow the solvent to absorb water from the gas. Inlet gas has 82 # water/mmscf at the inlet, and has less than 4# water/mmscf at the outlet of the contactor.

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www.huzykenergy.com sandra@huzyk.com

TEG that has absorbed water is termed 'rich' glycol. Not only do glycol compounds absorb water, they absorb some heavy hydrocarbons. Rich glycol is warmer than the lean glycol entering the contactor because of heat of absorption. It flows from the contactor bottom and into the condenser coils of the regenerator, discussed later. Leaving these coils in the top of the regenerator, the glycol has been further heated to approx.105 F. Flow continues through one barrel of the rich/lean exchanger.

Here, lean glycol from the regenerator (approx. 360 deg. F) exchanges more heat with the rich flow, increasing its temp to 150 F. The heated solvent flows to the lower pressure flash tank, which allows absorbed hydrocarbons to flash off as a gas, leaving the rich glycol mostly free of hydrocarbon contamination. The separated hydrocarbon gas and liquid flow to the BTEX and vapor recovery unit.

Rich glycol flows through charcoal and sock filters that will absorb oil and solid contaminants. Once scrubbed of contaminants, the flow continues through the last two barrels of the rich/lean exchanger, picking up heat from the lean glycol out of the heater.

By now the rich glycol is well over 200 deg. F, and feeds into the regenerator. This regenerator operates at a few inches of w.c., i.e. only about 0.5 psi. The combination of this low pressure and high temperature at the bottom, boils off water and hydrocarbons, regenerating the solvent. The solvent is now termed 'lean', as it is approx. 99.5 wt. % TEG out of the heater.

Cottonwood has a particular type of regenerator, called a Coldfinger. This unit has the capability of enhancing water removal via a condensing medium (rich TEG) in addition to the stripper overhead condensing . As well, there is a connection for a stripping gas sparge. These options can get TEG purity to 99.99 wt. %, resulting in gas dried to less than 0.5 #/mmscf. They are used only occasionally.

Lean, low pressure TEG flows down through the three barrels of the rich/lean exchanger, cooling as it goes. A pump boosts the liquid to contactor pressure. From pump discharge the lean TEG is cooled finally in the glycol/gas exchanger, entering the contactor at no more than 115 deg. F.

BTEX Removal

Regenerator and flash tank overheads are a source of hydrocarbon pollution if not properly captured and processed. Regenerator overhead gas flows to the BTEX recovery unit. This unitis an air-cooled, finned-tube, natural convection exchanger, followed by a separator that catches condensed liquid. It allows vapor to flash off. BTEX is an acronym for the contaminants, benzene, toluene, ethylbenzene and xylenes (ortho, meta and para-).

Noncondensible vapor from this vessel flows to the vapor recovery unit (suction 8" w.c.). Recovery of non-condensible vapor and delivery back to field inlet or into fuel gas is the key to zero-emission operation. In general, if VRU compressors are down, a BTEX unit would

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overpressure and emit HC vapor to atmosphere. This would happen because the glycol pumps would keep circulating TEG and keep absorbing hydrocarbons.

Cottonwood has taken away this possibility by hard-wiring safeguards:

1. If one VRU goes down the other comes on automatically
2. If neither VRU is operable the TEG circulation pumps shut down

I observed a test of this system. The operator shut down both VRUs and the circulation pumps shut down. PCV- 102B, set to open to atmosphere at 4 psig in the event of overpressure, stayed closed during this test and the rest of the visit. This regulator is on the inlet to the BTEX removal unit. It reacts to a rise in suction pressure above 4 psig.

Also hardwired is the regenerator's high pressure shutdown. If pressure reaches 80 in. w.c. (2.89 psig) not only does the burner shut down, the TEG circulation pumps also shut down, regardless of VRU status. I observed a successful test of this shutdown. The above regulator stayed closed.

Vapor Recovery Units

Hydrocarbon from the flash tank flows through V-144. Vapor disengages from the liquid and flows to the first VRU compressor. This unit compresses the gas from approx. 20 psig to 70 – 90 psig, depending on whether the vapor is returned to fuel gas or to gathering. Discharge gas is well over 100 deg. F. It flows through exchanger coils in the bottom of this vessel, heating liquid and keeping the VRU suction pressured with vapor. (A safeguard also exists, in which a low pressure suction triggers fuel gas flow that ensures a mimimum pressure for steady VRU operation.)

Any liquid trapped in the standpipe, used as a suction scrubber, flows to the low pressure (5-8 in. w.c.) vessel, V-140. Vapor from this overhead flows through two stages of VRU compression, each providing heat through vessel exchanger coils that keep vapor flowing to the units.

Liquids (water and hydrocarbon) commingle as shown, and go to the atmospheric tanks to be sold as condensate. Total liquid recovery from the BTEX and VRU sections is 14 bpd, or approximately 15 gal/mmscfd. This liquid has a 17 TVP and a 4 RVP.

The result of this design and operation is that Cottonwood dehydration is a zero-emission facility.

S L Huzyk

Sandra L. Huzyk, P. E.

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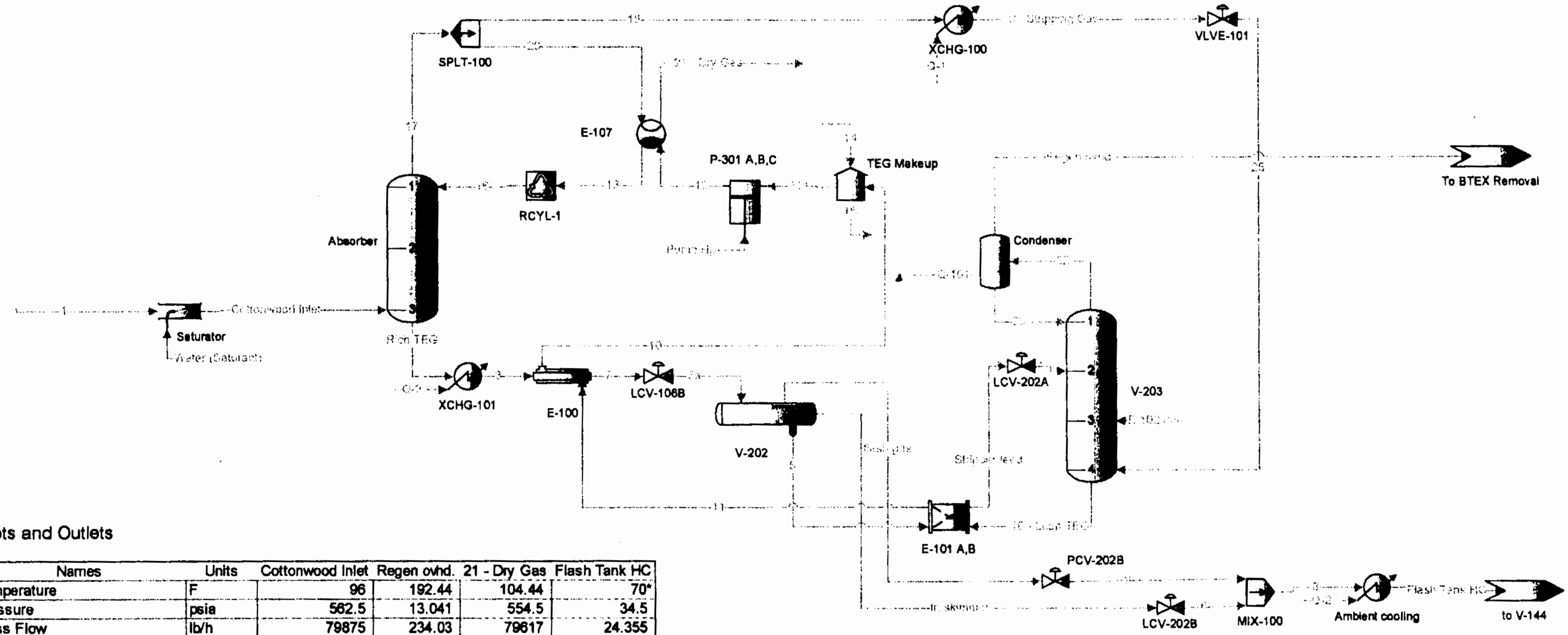


Inlets and Outlets

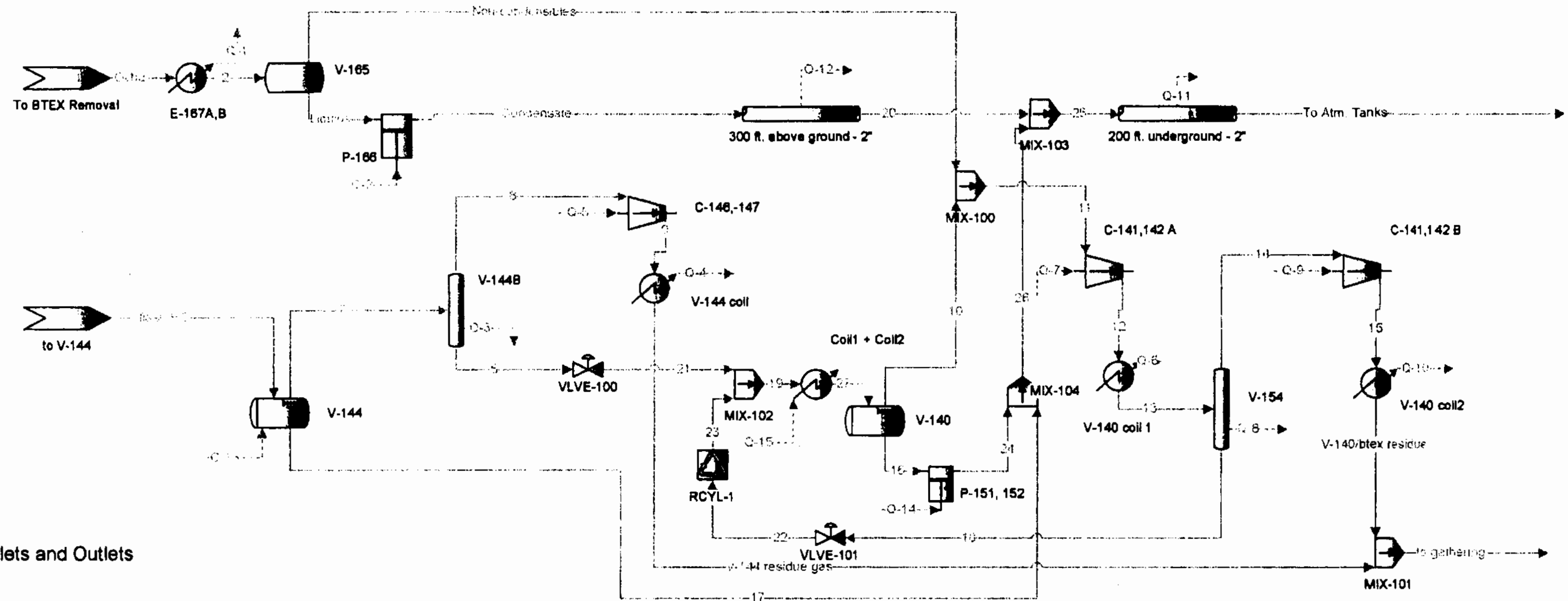
Names	Units	Cottonwood Inlet	Regen ovhd.	21 - Dry Gas	Flash Tank HC
Temperature	F	96	192.44	104.44	70*
Pressure	psia	562.5	13.041	554.5	34.5
Mass Flow	lb/h	79875	234.03	79617	24.355
Std Vapor Volumetric Flow	MMSCFD	40.069	0.08731	39.973	0.0087005
Propane(Mass Flow)	lb/h	3351.8	2.4552	3346.7	2.6228
i-Butane(Mass Flow)	lb/h	921.52	0.87184	919.83	0.82008
n-Butane(Mass Flow)	lb/h	1135.2	1.7177	1132.2	1.286
i-Pentane(Mass Flow)	lb/h	558.96	1.3318	556.91	0.72664
2,2-Dimethylbutane(Mass Flow)	lb/h	23.844	0.098547	23.709	0.036367
2,3-Dimethylbutane(Mass Flow)	lb/h	54.122	0.32725	53.703	0.09196
n-Pentane(Mass Flow)	lb/h	432.53	1.4676	430.41	0.65236
2-Methylpentane(Mass Flow)	lb/h	152.53	7.8451	144.29	0.3868
3-Methylpentane(Mass Flow)	lb/h	87.807	5.9372	81.638	0.23122
n-Hexane(Mass Flow)	lb/h	206.65	1.5648	204.71	0.36918
Cyclohexane(Mass Flow)	lb/h	103.86	5.0541	98.565	0.24504
Methylcyclohexane(Mass Flow)	lb/h	147.05	6.8805	139.84	0.32566
n-Heptane(Mass Flow)	lb/h	270.65	4.5566	265.55	0.54755
Octane(Mass Flow)	lb/h	80.27	2.9857	77.11	0.17409
Nonane(Mass Flow)	lb/h	38.867	3.7583	35.018	0.09053
Decane(Mass Flow)	lb/h	1.8747	0.42383	1.4463	0.0045447
Benzene(Mass Flow)	lb/h	40.481	7.5625	32.786	0.1326
Toluene(Mass Flow)	lb/h	46.132	14.488	31.486	0.15664
Water(Mass Flow)	lb/h	137.13	130.08	6.8686	0.19108

Liquid Circulation

Names	Units	10 - Lean TEG	Stripper feed	Rich TEG	fr. skimmer
Temperature	F	361.76	280*	98.565	
Pressure	psia	14	49	562.5	54
Mass Flow	lb/h	5078.7	5286.9	5311.3	0
Propane(Mass Flow)	lb/h	0.025281	1.3954	4.0182	0
I-Butane(Mass Flow)	lb/h	0.0085074	0.58213	1.4022	0
n-Butane(Mass Flow)	lb/h	0.013082	1.3637	2.6498	0
i-Pentane(Mass Flow)	lb/h	0.0083327	1.1595	1.8862	0
Benzene(Mass Flow)	lb/h	0.048683	7.6005	7.7331	0
Toluene(Mass Flow)	lb/h	0.18787	14.666	14.822	0
o-Xylene(Mass Flow)	lb/h	0.35912	8.4225	8.4638	0
Ethylbenzene(Mass Flow)	lb/h	0.014105	0.63224	0.63652	0
Std Liquid Volumetric Flow	sgpm	8.9996	9.4718	9.5939	0

Cottonwood Plant
Dehydration

May, 2006 Operation

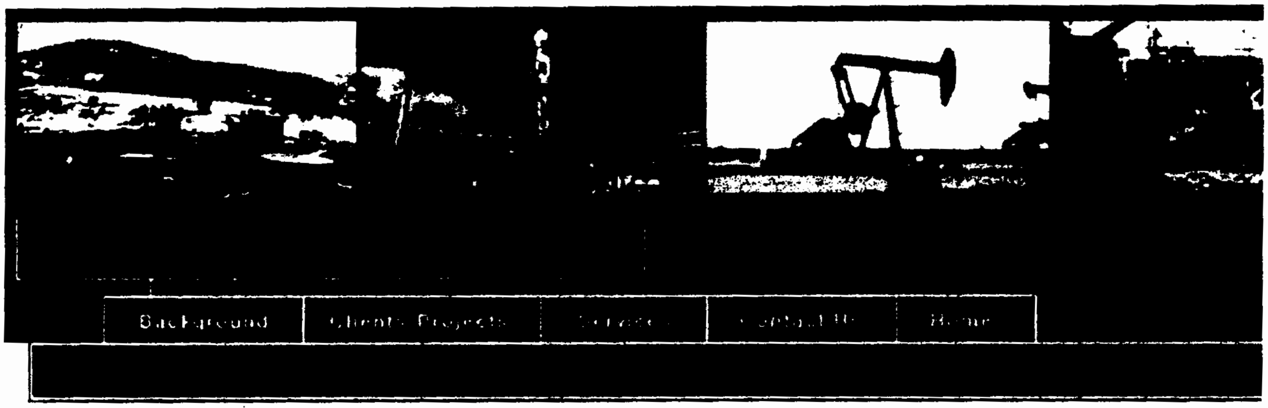


Inlets and Outlets

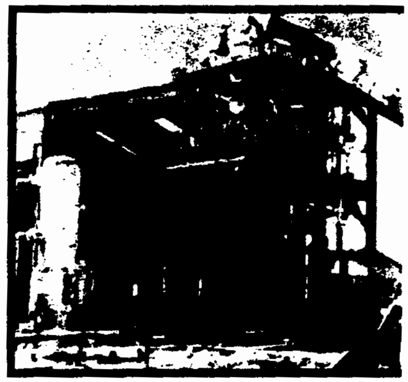
Names	Units	Ovhd.	flash HC	To Atm. Tanks	to gathering
Temperature	F	192.44	70	61.354	133.98
Pressure	psia	13.041	34.5	17.497	82
Mass Flow	lb/h	234.03	24.355	192.38	66.001
Std Vapor Volumetric Flow	MMSCFD	0.08731	0.0087005	0.071672	0.024339
Std Liquid Volumetric Flow	bbl/d	21.684	4.1864	14.457	11.413
Propane(Mass Flow)	lb/h	2.4652	2.6228	0.13102	4.947
i-Butane(Mass Flow)	lb/h	0.87184	0.82008	0.11973	1.5722
n-Butane(Mass Flow)	lb/h	1.7177	1.286	0.3324	2.6714
i-Pentane(Mass Flow)	lb/h	1.3318	0.72684	0.53343	1.525
2,2-Dimethylbutane(Mass Flow)	lb/h	0.098547	0.036367	0.081005	0.073909
2,3-Dimethylbutane(Mass Flow)	lb/h	0.32725	0.09196	0.23093	0.18827
n-Pentane(Mass Flow)	lb/h	1.4676	0.65236	0.71254	1.4074
2-Methylpentane(Mass Flow)	lb/h	7.8451	0.3868	5.055	3.1769
3-Methylpentane(Mass Flow)	lb/h	5.9372	0.23122	4.0067	2.1617
n-Hexane(Mass Flow)	lb/h	1.5648	0.36918	1.2849	0.64903
Cyclohexane(Mass Flow)	lb/h	5.0541	0.24504	4.0186	1.2805
Methylcyclohexane(Mass Flow)	lb/h	6.8805	0.32566	6.4372	0.76898
n-Heptane(Mass Flow)	lb/h	4.5568	0.54755	4.4904	0.61372
Octane(Mass Flow)	lb/h	2.9857	0.17409	3.0479	0.11195
Nonane(Mass Flow)	lb/h	3.7583	0.09053	3.8129	0.035988
Decane(Mass Flow)	lb/h	0.42383	0.0045447	0.42723	0.001154
Benzene(Mass Flow)	lb/h	7.5625	0.1326	5.8222	1.8729
Toluene(Mass Flow)	lb/h	14.488	0.15664	13.583	1.0612
o-Xylene(Mass Flow)	lb/h	8.0651	0.041251	7.9831	0.12332
Ethylbenzene(Mass Flow)	lb/h	0.61838	0.0042878	0.60753	0.015143
Water(Mass Flow)	lb/h	130.08	0.19108	129.61	0.66518

Cottonwood Plant
BTEX Removal and Vapor Recovery

May, 2006 Operation



Sandra L. Huzyk, P. E. began Huzyk Energy Management, Inc. in 1993 as a consulting engineering and process safety management company to help oil and gas companies manage production and processing for profit and safety. Just past its 11th anniversary, HEM has evolved into chemical engineering consulting, design and project management for energy, chemical, research and other industries.



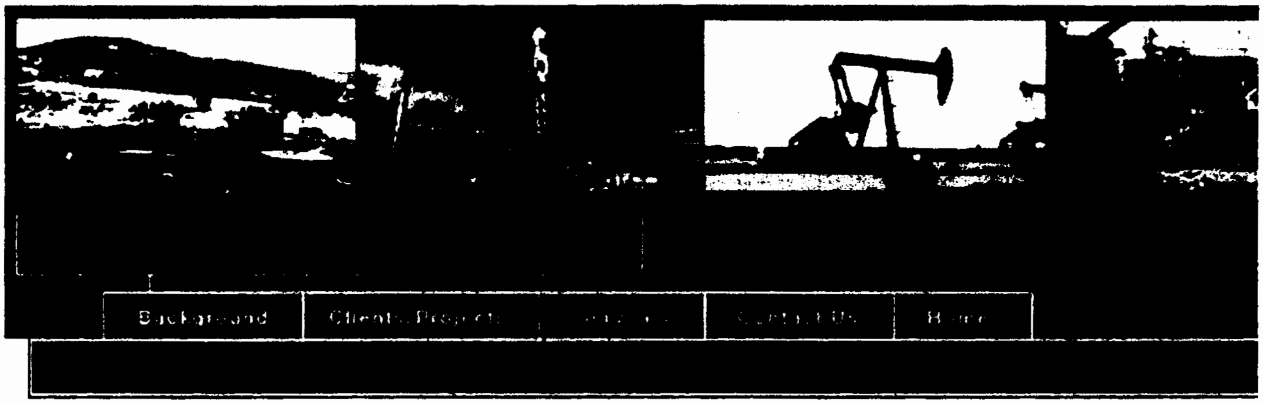
Direct Oxidation Pilot Plar

Sandra has been a chemical engineer for 26 years. She was a process engineer for Amoco Production Company for 11 years and project manager for an engineering company for 3 years. Most of this time was spent in the design, construction, startup and optimization of refrigeration, expander, cryogenic and fractionation plants; such as the 50 MMSCFD A.R.E. East Lobe expander plant, the 400 MMSCFD Anschutz NGL/NRU and the 250 MMSCFD Painter NGL/NRU.

She began her treating and sulfur recovery design/operating experience in 1982 on the 275 MM (1100 ltd) Whitney Canyon plant and the ULTRA pilot plant. She has continued hydrocarbon rec dehydration, sweetening, sulfur recovery and tailgas cleanup projects since then.

Sandra has a BS in Chemistry from the University of Colorado (Colorado Springs; 1976) and an Chemical and Petroleum Refining Engineering from Colorado School of Mines; 1980.

Publication:
"Anschutz Ranch East Facilities Development";
June 13, 1998, Oil and Gas Journal.



A Short Client List with typical Process Design, Project Management and Consulting Pr

Forest Oil
Feasibility Study, Design and skid-mounting 20 mmscfd selexol
a) Project Management: Plant on 56% CO_2
b) Allocation audit on 40 MMSCFD Uintah Basin plant

BP-Amoco Oil
a) Provided preliminary engineering, PFDs and installed project cost/economics for the upgrade of a 52,000 bpd BP fractionation complex to 85,000 bpd; as well as for the addition of a CO2 removal unit and a butane splitter.
b) Increased the capacity of the Painter Fractionation Facility from 7500 bpd to 9400 bpd for ¼ of the proposed budget, and assisted in PSM management of change tasks.

TDA Reasearch, Inc.
Provided bid packages, project engineering and project management for the completed design and installation of a direct-oxidation sulfur recovery pilot plant to test client's patented catalyst. Provided assistance with startup and operation, until turned over for day-to-day operation. HEM also found and negotiated rights to the host site.

Direct-oxidation SRU technology licensed by SulfaTreat, 2004.

Encana Gathering Services
Provided preliminary engineering and several after-tax economic scenarios for construction of 250 MMSCFD refrigeration and expander plants

Bear Paw Energy
HEM acted as Engineering Manager for the startup company, hiring employees, setting up PSM program and building the following projects:
a) refurbished and installed a used, 20 gpm amine plant at Baker, MT
b) installed a satellite compressor station, outside Baker, MT
c) installed deisobutanizer in fractionation plant outside Sidney, MT
d) 2005 capacity study for stablilization, compression, expander, and fractionation trains of 60 MMSCFD Grasslands plant.

Laramie Energy
Design and installation of two dewpoint control plants (compression, CO_2 removal, dehydration, J-T skid) in the Piceance Basin.

Radian International, LLC
Collaboration on tailgas treating study to spec equipment and determine operating costs. Results compiled in the paper, "H2S Removal and Sulfur Recovery Options for High Pressure Natural Gas with Medium Amounts of Sulfur". Presented by Radian (Crystasulf) engineers Nov. 1, 2000 at the Sulfur 2000 International Conference in San Francisco.

Duke Energy Field Services
Successfully completed consulting assignment to increase the throughput of a 35 MMSCFD expander plant to 47 MMSCFD. Also detailed a solution approved by plant and management to avoid the installation of a TEG dehydration plant, while increasing condensate production by 50 bpd.

Facility Description

Facility Description

Anadarko Uintah Midstream LLC (Anadarko) owns and operates the Cottonwood Wash Compressor station (Cottonwood), within the exterior boundaries of the Uintah and Ouray Indian Reservation, in Uintah County, Utah.

On November 12, 1996 the State of Utah issued Approval Order DAQE-1037-96 to Coastal Oil and Gas Corporation for the Cottonwood Wash (formerly West) Compressor Station. The Approval Order was issued for one 1,100hp Caterpillar 3516TALE compressor engine. The order does not list any other equipment at the facility. Facility emissions were limited to 19.97 tpy NOx, 19.97 tpy CO, and 7.49 tpy VOC.

In December 2001 the name was changed from Coastal Field Services to El Paso Production Oil and Gas Company and on December 18, 2002, Westport Oil and Gas LP (WOG) acquired the facility from El Paso.

In July 2003 WOG personnel were made aware that the State of Utah did not have authority to issue air quality permits for this facility as is was within the Tribal Airshed.

On July 18, 2003, WOG submitted a notice to the Uintah and Ouray Reservation of intent to install two Caterpillar G3516TALE engines and a 50 MMSCFD TEG dehydration unit with condenser and flare. The same notice was submitted to the State of Utah on July 24, 2003.

On October 13, 2003, a 1,340-hp Caterpillar G3516LE compressor engine (ENG-2) was installed. In January 2004, the engine that was authorized under Approval Order DAQE-1037-96 was replaced with a like-kind unit (unit represented as ENG-WEST). On June 28, 2004 one more 1,340-hp Caterpillar G3516LE compressor engine was installed (ENG1). On June 29, 2004 the State of Utah revoked Approval Order DAQE-1037-96 for the West Compressor Station.

An Initial Part 71 Permit Application was submitted on December 14, 2004. The facility-wide PTE was 84.1 tpy of NO_x, 100.8 tpy of CO, 459.4 tpy of VOC and 248.8 tpy of HAPs. On February 22, 2005 WOG submitted a response to the Part 71 application incomplete letter issued by the EPA on February 11, 2005. In this application the 0.125 MMBtu/hr heater was listed as an insignificant source and the fugitives were added on form PTE which was now estimated to be 84.0 tpy of NO_x, 100.8 tpy of CO, 467.2 tpy of VOC and 249.3 tpy of HAPs.

In March of 2005 refrigeration units were installed at the facility and that portion of the facility became subject to Subpart 40 CFR 60 Subpart KKK. In addition, new chips to monitor catalyst temperature on the engines were installed to fulfill RICE MACT requirements. On April 9, 2005, a low-emissions dehydrator and associated reboiler were installed to replace the existing 50 MMSCFD TEG dehydrator was dismantled and removed. A Part 71 permit modification was submitted on May 25, 2005 requesting the inclusion of the newly installed equipment. Facility-wide PTE was 89.4 tpy of NO_x, 123.4 tpy of CO, 58.6 tpy of VOC and 19.7 tpy of HAPs.

A Part 71 permit update was submitted on October 11, 2005 requesting that the semiannual reporting period be modified to allow for submitting reports based on the calendar year. In addition, WOG installed ENG-4 in July of 2005 and upgraded engines ENG-2 and ENG-WEST with new air to fuel ratio controllers, which increased the horsepower rating from 1,265-hp to 1,340-hp. The new facility-wide PTE was 79.3 tpy of NO_x, 127.5 tpy of CO, 59.6 tpy of VOC and 20.1 tpy of HAPs.

On January 19, 2006, Kerr-McGee Oil & Gas Onshore LP, on behalf of Westport Oil and Gas LP, submitted to the EPA a Notification of Permit Application Transfer to its affiliate Westport Field Services LLC (Westport).

In April of 2006, Westport installed a Caterpillar G3516TALE compressor engine (ENG-5) and increased throughput through the existing dehydrator to 80 MMSCFD and a permit update was submitted on May 5, 2006. Facility PTE was 98.7 tpy of NO_x, 159.0 tpy of CO, 61.4 tpy of VOC and 22.0 tpy of HAPs. This permit application update was followed by another application modification submitted on June 14, 2006 to include form I-COMP for compliance demonstration.

In April of 2007 a Caterpillar G3516TALE (ENG-6) was installed, ENG-4 was removed and a VRU was added to control flash emissions from the condensate tanks. Westport re-submitted a complete Part 71 permit application per EPA's request on December 17, 2007 stating a PTE of 97.6 tpy of NO_x, 11.6 tpy of CO, 30.2 tpy of VOC and 3.1 tpy of HAPs.

On March 27, 2008, a Consent Decree was entered by the U.S. District Court against Westport and its parent company requiring that all compressor engines be retrofitted with emissions control equipment. On March 28, 2008 a flare (FLR) was installed as a VRU back-up control for the condensate tanks. An updated Part 71 permit application was submitted on August 7, 2008 requesting a company name change to Anadarko Uintah Midstream LLC (Anadarko). In addition, Westport requested that the resulting emissions from the control equipment established under the Consent Decree to be considered for the purposes of calculating PTE as these were federally enforceable. The resulting facility-wide PTE was 97.8 tpy of NO_x, 12.7 tpy of CO, 34.9 tpy of VOC and 7.5 tpy of HAPs.

On August 7, 2008 Anadarko installed a Caterpillar G3608LE (ENG-WEST2) and removed ENG-WEST1 on August 27, 2008. Gas processing was suspended and the process disconnected at the facility on September 23, 2008. Consequently, the Subpart 40 CFR 60 Subpart KKK and the leak detection and repair program were suspended. Anadarko submitted an update to the Part 71 permit application on March 27, 2009 stating a facility-wide PTE of 112.7 tpy of NO_x, 14.5 tpy of CO, 37.3 tpy of VOC and 9.1 tpy of HAPs.

Anadarko submitted a Part 71 permit modification on March 1, 2010 to correct NOx emission factors for ENG-WEST2 and on March 30, 2010 to change the company's responsible official. The estimated facility-wide PTE was 97.4 of NO_x, 14.5 tpy of CO, 37.3 tpy of VOC and 9.1 tpy of HAPs. Additional information was submitted on October 7, 2010 and a limit request on December 8, 2010. The facility PTE was 110.4 of NO_x, 18.5 tpy of CO, 44.1 tpy of VOC and 12.0 tpy of HAPs.

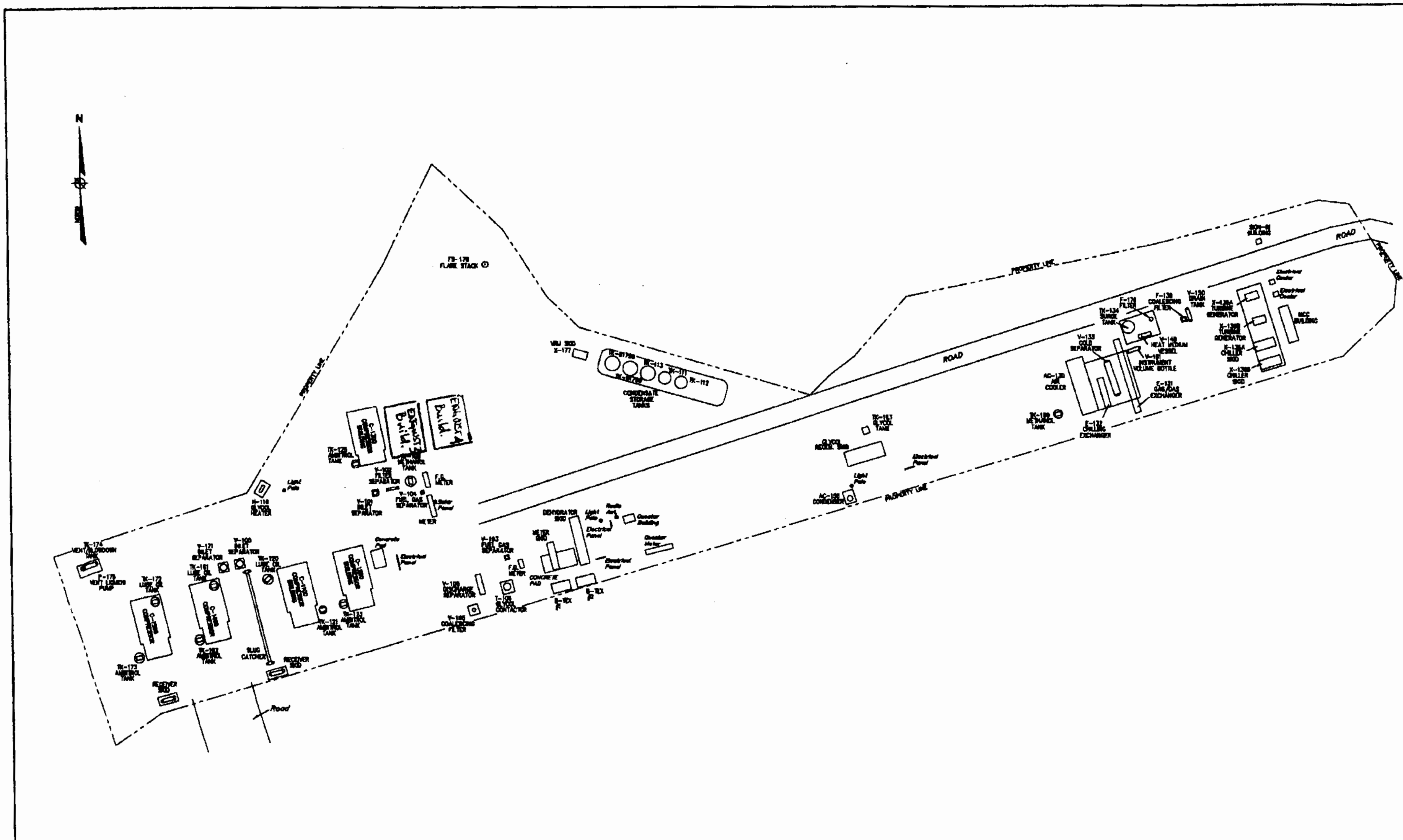
In November of 2011, Anadarko informed EPA that VRU had been replaced with a blowcase system.

Anadarko submitted a Part 71 permit modification on December 12, 2011 for inclusion of one new Caterpillar G3608 LE engine (ENG-WEST 4), update like-kind replacement information for engines ENG-1, ENG-4 and ENG-5, update CO emission factors and fuel usage for ENG-1, ENG-2, ENG-4 and ENG-5, and update CH2O emission factors and fuel usage for ENG-WEST-2 and ENG-WEST-3.

Anadarko recently installed two new Caterpillar 3606 LE engines (ENG-WEST-5 & ENG-WEST-6). Below is the equipment list at the facility:

Unit	Description	Control Equipment
ENG1	1340 hp Cat G3516 TALE Engine, S/N: 4EK04362	Oxidation Catalyst
ENG2	1340 hp Cat G3516 TALE Engine, S/N: 4EK04357	Oxidation Catalyst
ENG4	1340 hp Cat G3516 LE Engine, S/N: 4EK04364	Oxidation Catalyst
ENG5	1340 hp Cat G3516 LE Engine, S/N: 4EK04366	Oxidation Catalyst
ENG-WEST-2	2370 hp Cat G3608 LE Engine, S/N: BEN00391	Oxidation Catalyst
ENG-WEST-3	2370 hp Cat G3608 LE Engine, S/N: BEN00626	Oxidation Catalyst
ENG-WEST-4	2370 hp Cat G3608 LE Engine, S/N: BEN00590	Oxidation Catalyst
ENG-WEST-5	1775 hp Cat G3606 LE Engine, S/N: 4ZS00751	Oxidation Catalyst
ENG-WEST-6	1775 hp Cat G3606 LE Engine, S/N: 4ZS00755	Oxidation Catalyst
REBLR-2	1.4 MMBtu/hr Dehy Reboiler	None
DEHY-LO	80 MMscfd Low Emissions Dehy	None
TANKBAT	3-400 bbl	Flare
TANKFLR	VRU Backup Flare	None
FUG	Facility Fugitives	None
HTR	0.25 MMBtu/hr Trace Heater	None
GEN1	250 kW Ingersoll-Rand Microturbine Generator	None
GEN2	250 kW Ingersoll-Rand Microturbine Generator	None

Plot Plan



-K:\GROUP\COMPRESSION\COMPRESSOR STA DWGS\UTAH\WEST\SITE PLAN\U1-GP-01.DWG JES PLT SCALE: 1 = 1 2:00 12/13/08

REV.	DESCRIPTION	DATE	BY	CHK'D	ENG	DISC	PRJ
4	FS-178 FLARE STACK ADDED	5/2/08	JES				
3	AS-BUILT UP-DATE	1/17/08	JES				
2	ADDED VENT BLOWDOWN TANK, LIQUIDS PUMP, & SLUG CATCHER	1/13/08	JES				DG
	RELOCATED H-118 GLYCOL HEATER & CONDENSATE STORAGE AREA						
1	ADDED V-188 COALESCING FILTER	8/6/08	JES				
0	AS-BUILT	8/16/06	JES				MA
A	PRELIMINARY	10/14/06	JES				CR

ENGINEERING REVIEW		
DISCIPLINE	REVIEWED	DATE
PROCESS		
MECHANICAL		
PIPING		
ELECTRICAL		
I & C		
CIVIL/STRUCTURAL		
PROJECT		

REFERENCE DRAWINGS	
NO.	DESCRIPTION

WESTPORT
COTTONWOOD/WEST COMPRESSOR STATION
PLOT PLAN

CLIENT No.:	CLIENT APPR.:	APPR. DATE:
REQ No.:	SCALE: NONE	CREATION DATE:
DRAWN BY: J E SMITH	DWG. No.: U1-GP-01	SHEET No. OF

Process Description and Process Flow Diagram

Process Description

Natural gas from the field enters the station through a 10 inch intermediate pressure line at about 350 psig or the 12, 10 and 8 inch diameter low pressure pipelines at about 75 psig. Free liquids are dropped out in the inlet slug catcher with condensate going to the blowcase system and water to the tank battery (TANKBAT). The tanks are controlled by a flare (TANKFLR) for combustion. Natural gas from the inlet separators is sent to either the low pressure reciprocating compressors driven by natural gas fired reciprocating internal combustion engines (ENG-WEST-2, ENG-WEST-3, ENG-WEST-4, ENG-WEST-5 and ENG-WEST-6) and compressed to about 350 psig or to the intermediate pressure compressors driven by gas engines (ENG1, ENG2, ENG4 and ENG5) and compressed to about 935 psig. The high pressure gas then goes through the Sulfa-Check liquid contactors for sulfur removal and then through the low-emission dehydration unit (DEHY-LO) to lower the water content to pipeline specifications prior to leaving the outlet of the station.

Pigging operations are conducted at the compressor station on the 12 inch line approximately once per month and on the 10 inch line about twice a month and all pigged liquids are collected in the inlet separators. The only emissions would be generated when the pig chamber is depressurized to remove the pig. These emissions are minimal.

Emission Control Description

Emission Control Description

Engines

All the existing engines at this site are 4 stroke lean burn engines. These engines are equipped with oxidation catalysts to control emissions.

Temperature-sensing devices are installed at the inlet of the catalyst to ensure the temperature at the inlet of the catalyst does not exceed optimal range specified by the manufacturer. The pressure shall be measured before and after the catalyst on a monthly basis to ensure that the pressure drop across the catalyst does not exceed the optimal range specified by the manufacturer. The engines shall be fired with pipeline quality natural gas to ensure that there are no contaminants in the fuel that might foul the catalysts.

Maintenance shall be performed routinely per vendor recommendations or the facility's maintenance plan. The components shall be serviced or replaced as needed.

Dehydrators

The existing dehydrator (DEHY-LO) is a low emissions dehydrator with emissions of less than 1.0 tpy of VOC. No further emission controls are required on this unit.

Tank Battery

The Tank Battery is equipped with a flare for control of VOCs

Supporting Documentation

Uncontrolled CO

1340 x 4 - 24.07 x 3 = 72.21

1775 x 2 = 42.8 x 2 = 85.6

2370 x 3 = 57.21 x 3 - 171.63

329.44

Uncontrolled VOC

~~1340 x 4 = 9.06~~

~~1775 x 2 =~~

2370 x 3 =

				C)	SOx (tpy)	PM10 (tpy)	CO2e (tpy)	CH_2O (tpy)	HAPs (tpy)
				1	0.03	0.4	4713.7	0.9	1.3
				1	0.03	0.4	4713.7	0.9	1.3
				1	0.03	0.4	4713.7	0.9	1.3
				1	0.03	0.4	4713.7	0.9	1.3
				.0	0.04	0.7	7430.7	1.4	2.1
				.0	0.04	0.7	7430.7	1.4	2.1
				5.0	0.04	0.7	7430.7	1.4	2.1
				2.0	0.0	0.0	5967.4	1.6	2.2
				2.0	0.0	0.0	5967.4	1.6	2.2
				).0	0.003	0.0	717.5	0.0	0.0
				1.0					
TANKBAT	Condensate Storage								
TANKFLR	Tank Battery Flare	0.3	1.0	0.8			508.6		0.0
FUG	Facility Fugitives			12.2					0.8
TANKS	2 - 400 bbl Produced Water Tanks			2.4					0.2
GEN1	250kW Ingersoll-Rand Turbine Generator	0.01	0.01	0.00	0.00	0.00			0.00
GEN2	250kW Ingersoll-Rand Turbine Generator	0.01	0.01	0.00	0.00	0.00			0.00
HTR	0.25 MMBtu/hr Trace Heater	0.10	0.08	0.01	0.000	0.01		0.00	0.00
Facility Totals		**176.5**	**232.0**	**124.6**	**0.3**	**3.8**	**54307.7**	**11.2**	**17.1**

Cottonwood Wash Compressor Station
Tank Detail Sheet

Source Id	Throughput bbls/day	Uncontrolled Emissions				Controlled Emissions *	
		VOC		HAPs		VOC	HAPs
		lb/hr	tpy	lb/hr	tpy	tpy	tpy
TANKBAT	13		15.00	0.55	0.75	0.75	0.04

* Controlled Emissions based on 95% destruction efficiency for Flare.

Emissions based on Ouray Promax run 1.15 tons VOC/bbl/day

Cottonwood Wash Compressor Station
Flare Detail Sheet

Source ID Number	**TANKFLR**	Source Location	Zone:
Source Description	Flare		UTME:
Equipment Usage	Controls Storage Tank Emissions		UTMN:
Equipment Make			
Equipment Model		Potential operation	8760 hr/yr
Serial Number			
Date in Service	3/28/2008	Potential fuel usage	5.48 MMscf/yr
Equipment Configuration			625 scf/hr

Pilot Fuel Heating Value	1109 Btu/scf	Stack ID	**TANKFLR**
Pilot Gas Design Flow Rate	0.015 MMscfd	Stack Height	25 ft, agl
Recovered Gas Heating Value	2177 Btu/scf	Stack Diameter	12 in
Recovered Gas Flow Rate	0.0033 MMscfd	Exit Velocity	60 ft/s
Total Heat Input Rating	0.992 MMBtu/hr	Exit Temperature	1000 deg F
		Volume Flow Rate	2827 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	(lb/yr)	Source of Emission Factors
NOx	0.068	8760	0.07	0.30	591.2	AP-42 Table 13.5-1
CO	0.37	8760	0.37	1.61	3216.8	AP-42 Table 13.5-1

Notes
1) Recovered gas heating value from E&P Tanks Run.

CO2e Emission Calculations

__Conversions:__

1 Metric Ton = 2204.62 lbs
1 kg = 0.001 metric tons

Pollutant	kg/mmbtu	metric ton	tpy
CO_2	53.02	461	508
CH_4	0.001	0	0
N_2O	0.0001	0	0
		CO_{2e} =	509

$CO_{2e} = CO_2 + (CH_4*21) + (N_2O*310)$

GHG emission factors from '40 CFR 98 Table C-1, C-2.

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG1**		
Source Description	1340 hp Cat G3516 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3516 LE		
Serial Number	4EK04362		
Date in Service	6/6/2011	Potential fuel usage	78.4 MMscf/yr
Emission Controls	Lean Burn		8947 scf/yr
	Oxidation Catalyst		
		Stack ID	**ENG1**
Site Rating	1340 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.06 ft
Heat Rate	9.92 MMBtu/hr	Exit Velocity	144.9 ft/s
Engine Heat Rate	7405 Btu/hp-hr	Exit Temperature	873 deg F
		Volume Flow Rate	7,664 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.88	Mfr Data
CO	0.55	1.86	1340	8760	5.49	24.07	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.06	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.03	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.43	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.29	1340	8760	0.86	3.75	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.02	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.011	0.05	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.083	0.36	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.9	Mfr Data
CO	0.36	1.21	1340	8760	3.57	15.6	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.1	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.4	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.07	1340	8760	0.21	0.9	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.01	0.0	AP-42, Table 3.2-2

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG2**		
Source Description	1340 hp Cat G3516 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3516 LE		
Serial Number	4EK04357		
Date in Service	10/13/2003	Potential fuel usage	78.4 MMscf/yr
Emission Controls	Lean Burn		8947 scf/yr
	Oxidation Catalyst		
		Stack ID	**ENG2**
Site Rating	1340 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.06 ft
Heat Rate	9.92 MMBtu/hr	Exit Velocity	144.9 ft/s
Engine Heat Rate	7405 Btu/hp-hr	Exit Temperature	873 deg F
		Volume Flow Rate	7,664 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.88	Mfr Data
CO	0.55	1.86	1340	8760	5.49	24.07	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.06	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.03	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.43	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.29	1340	8760	0.86	3.75	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.02	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.011	0.05	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.083	0.36	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.9	Mfr Data
CO	0.36	1.21	1340	8760	3.57	15.6	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.1	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.4	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.07	1340	8760	0.21	0.9	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.01	0.0	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.08	0.4	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-4**		
Source Description	1340 hp Cat G3516 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3516 LE		
Serial Number	4EK04364		
Date in Service	1/28/2011	Potential fuel usage	78.4 MMscf/yr
Emission Controls	Lean Burn		8947 scf/yr
	Oxidation Catalyst		
		Stack ID	**ENG4**
Site Rating	1340 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.06 ft
Heat Rate	9.92 MMBtu/hr	Exit Velocity	144.9 ft/s
Engine Heat Rate	7405 Btu/hp-hr	Exit Temperature	873 deg F
		Volume Flow Rate	7,664 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.88	Mfr Data
CO	0.55	1.86	1340	8760	5.49	24.07	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.06	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.03	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.43	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.29	1340	8760	0.86	3.75	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.02	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.011	0.05	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.083	0.36	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.9	Mfr Data
CO	0.36	1.21	1340	8760	3.57	15.6	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.1	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.4	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.07	1340	8760	0.21	0.9	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.01	0.0	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.08	0.4	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-5**		
Source Description	1340 hp Cat G3516 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3516 LE		
Serial Number	4EK04366		
Date in Service	3/25/2011	Potential fuel usage	78.4 MMscf/yr
Emission Controls	Lean Burn		8947 scf/yr
	Oxidation Catalyst		
		Stack ID	**ENG5**
Site Rating	1340 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.06 ft
Heat Rate	9.92 MMBtu/hr	Exit Velocity	144.9 ft/s
Engine Heat Rate	7405 Btu/hp-hr	Exit Temperature	873 deg F
		Volume Flow Rate	7,664 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.88	Mfr Data
CO	0.55	1.86	1340	8760	5.49	24.07	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.06	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.03	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.43	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.29	1340	8760	0.86	3.75	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.02	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.011	0.05	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.083	0.36	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.60	2.00	1340	8760	5.91	25.9	Mfr Data
CO	0.36	1.21	1340	8760	3.57	15.6	Mfr Data
VOC	0.21	0.70	1340	8760	2.07	9.1	Mfr Data
SOx	0.000588	0.002	1340	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0335	1340	8760	0.10	0.4	AP-42, Table 3.2-2
CO2e	108.5	364	1340	8760	1076.2	**4713.73**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.07	1340	8760	0.21	0.9	Mfr Data
Benzene	4.40E-04	0.0015	1340	8760	0.004	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0037	1340	8760	0.01	0.0	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0281	1340	8760	0.08	0.4	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-WEST-2**		
Source Description	2370 hp Cat G3608 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3608 LE		
Serial Number	BEN00391		
Date in Service	8/7/2008	Potential fuel usage	124 MMscf/yr
Emission Controls	Lean Burn		14105 scf/yr
	Oxidation Catalyst		
		Stack ID	**ENG-WEST-2**
Site Rating	2370 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.06 ft
Heat Rate	15.6 MMBtu/hr	Exit Velocity	301.7 ft/s
Engine Heat Rate	6600 Btu/hp-hr	Exit Temperature	899 deg F
		Volume Flow Rate	15,955 ft^3/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
CO	0.84	2.50	2370	8760	13.06	57.21	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.04	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.68	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.26	2370	8760	1.36	5.95	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.03	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.017	0.08	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.131	0.57	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
CO	0.54	1.63	2370	8760	8.49	37.2	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.7	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.06	2370	8760	0.33	1.4	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.02	0.1	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.13	0.6	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-WEST-3**		
Source Description	2370 hp Cat G3608 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3608 LE		
Serial Number	BEN00626		
Date in Service	9/10/2010	Potential fuel usage	124 MMscf/yr
Emission Controls	Lean Burn		14105 scf/hr
	Oxidation Catalyst		
		Stack ID	**ENG-WEST-3**
Site Rating	2370 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.6 ft
Heat Rate	15.6 MMBtu/hr	Exit Velocity	121.0 ft/s
Engine Heat Rate	6600 Btu/hp-hr	Exit Temperature	899 deg F
		Volume Flow Rate	15,955 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
CO	0.84	2.50	2370	8760	13.06	57.21	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.04	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.68	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.26	2370	8760	1.36	5.95	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.03	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.017	0.08	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.131	0.57	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
CO	0.54	1.63	2370	8760	8.49	37.2	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.7	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.06	2370	8760	0.33	1.4	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.02	0.1	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.13	0.6	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-WEST-4**		
Source Description	2370 hp Cat G3608 LE Engine		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar		
Engine Model	G3608 LE		
Serial Number	BEN00590		
Date in Service	7/14/2011	Potential fuel usage	124 MMscf/yr
Emission Controls	Lean Burn		14105 scf/hr
	Oxidation Catalyst		
		Stack ID	**ENG-WEST-4**
Site Rating	2370 BHP	Stack Height	20 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.6 ft
Heat Rate	15.6 MMBtu/hr	Exit Velocity	121.0 ft/s
Engine Heat Rate	6600 Btu/hp-hr	Exit Temperature	899 deg F
		Volume Flow Rate	15,955 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
CO	0.84	2.50	2370	8760	13.06	57.21	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.02	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.04	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.68	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.09	0.26	2370	8760	1.36	5.95	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.03	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.017	0.08	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.131	0.57	AP-42, Table 3.2-2

Controlled Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (g/hp-hr)	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
CO	0.54	1.63	2370	8760	8.49	37.2	Mfr Data
VOC	0.23	0.70	2370	8760	3.66	16.0	Mfr Data
SOx	0.000588	0.002	2370	8760	0.01	0.0	AP-42, Table 3.2-2
PM10	9.99E-03	0.0299	2370	8760	0.16	0.7	AP-42, Table 3.2-2
CO2e	108.5	325	2370	8760	1696.5	**7430.66**	GHG Subpart C Cal
HAPs							
HCHO	0.02	0.062	2370	8760	0.33	1.4	Mfr Data
Benzene	4.40E-04	0.0013	2370	8760	0.007	0.0	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.0033	2370	8760	0.02	0.1	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.0250	2370	8760	0.13	0.6	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-WEST-5**		
Source Description	4-Cycle Lean Burn		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar	Potential operation	8760 hr/yr
Engine Model	G3606 LE		
Serial Number	4ZS00751	Potential fuel usage	99.2 MMscf/yr
Date in Service	1/18/2012		11327 scf/hr
Emission Controls	Lean Burn, Low Emissions Oxidation Catalyst		
		Stack ID	**ENG-WEST-5**
Site Rating	1775 BHP	Stack Height	32.80 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.66 ft
Heat Rate	12.56 MMBtu/hr	Exit Velocity	92.4 ft/s
Engine Heat Rate	7077 Btu/hp-hr	Exit Temperature	868 deg F
		Volume Flow Rate	11,989 ft³/min

Uncontrolled Emissions

Pollutant	Emission Factor		Rating	Operating Hrs	Estimated Emissions		Source of Emission
	(lb/MMBtu)	(g/hp-hr)	(hp)	(hrs/yr)	(lb/yr)	(tpy)	Factor
NOx	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
CO	0.78	2.50	1775	8760	85699.2	**42.8**	Manuf. Data
VOC	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
SOx	5.88E-04	0.002	1775	8760	64.7	**0.03**	AP-42, Table 3.2-2
PM10	7.71E-05	0.0002	1775	8760	8.5	**0.00**	AP-42, Table 3.2-2
CO2e	108.5	348	1775	8760	1362.4	**5967.4**	GHG Subpart C Calc
HAPs							
HCHO	0.12	0.40	1775	8760	13711.9	**6.86**	AP-42, Table 3.2-2
Benzene	4.40E-04	0.001	1775	8760	48.4	**0.024**	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.004	1775	8760	122.1	**0.061**	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.027	1775	8760	919.9	**0.460**	AP-42, Table 3.2-2

PTE Emissions

Pollutant	Emission Factor		Rating	Operating Hrs	Estimated Emissions		Source of Emission
	(lb/MMBtu)	(g/hp-hr)	(hp)	(hrs/yr)	(lb/yr)	(tpy)	Factor
NOx	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
CO*	0.51	1.63	1775	8760	55704.5	**27.9**	Manuf. Data
VOC*	0.22	0.70	1775	8760	23995.8	**12.00**	Manuf. Data
SOx	5.88E-04	0.002	1775	8760	64.7	**0.03**	AP-42, Table 3.2-2
PM10	7.71E-05	0.0002	1775	8760	8.5	**0.00**	AP-42, Table 3.2-2
CO2e	108.5	348	1775	8760	1362.4	**5967.4**	GHG Subpart C Calc
HAPs							
HCHO*	0.03	0.10	1775	8760	3290.9	**1.65**	Manuf. Control Data
Benzene	4.40E-04	0.001	1775	8760	48.4	**0.024**	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.004	1775	8760	122.1	**0.061**	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.027	1775	8760	919.9	**0.460**	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Engine Detail Sheet

Source ID Number	**ENG-WEST-6**		
Source Description	4-Cycle Lean Burn		
Engine Usage	Compressor Engine		
Engine Make	Caterpillar	Potential operation	8760 hr/yr
Engine Model	G3606 LE		
Serial Number	4ZS00755	Potential fuel usage	99.2 MMscf/yr
Date in Service	1/19/2012		11327 scf/hr
Emission Controls	Lean Burn, Low Emissions Oxidation Catalyst		
		Stack ID	**ENG-WEST-6**
Site Rating	1775 BHP	Stack Height	32.80 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter	1.66 ft
Heat Rate	12.56 MMBtu/hr	Exit Velocity	92.4 ft/s
Engine Heat Rate	7077 Btu/hp-hr	Exit Temperature	868 deg F
		Volume Flow Rate	11,989 ft^3/min

Uncontrolled Emissions

Pollutant	Emission Factor		Rating	Operating Hrs	Estimated Emissions		Source of Emission
	(lb/MMBtu)	(g/hp-hr)	(hp)	(hrs/yr)	(lb/yr)	(tpy)	Factor
NOx	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
CO	0.78	2.50	1775	8760	85699.2	**42.8**	Manuf. Data
VOC	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
SOx	5.88E-04	0.002	1775	8760	64.7	**0.03**	AP-42, Table 3.2-2
PM10	7.71E-05	0.0002	1775	8760	8.5	**0.00**	AP-42, Table 3.2-2
CO2e	108.5	348	1775	8760	1362.4	**5967.4**	GHG Subpart C Calc
HAPs							
HCHO	0.12	0.40	1775	8760	13711.9	**6.86**	AP-42, Table 3.2-2
Benzene	4.40E-04	0.001	1775	8760	48.4	**0.024**	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.004	1775	8760	122.1	**0.061**	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.027	1775	8760	919.9	**0.460**	AP-42, Table 3.2-2

PTE Emissions

Pollutant	Emission Factor		Rating	Operating Hrs	Estimated Emissions		Source of Emission
	(lb/MMBtu)	(g/hp-hr)	(hp)	(hrs/yr)	(lb/yr)	(tpy)	Factor
NOx	0.22	0.70	1775	8760	23995.8	**12.0**	Manuf. Data
CO*	0.51	1.63	1775	8760	55704.5	**27.9**	Manuf. Data
VOC*	0.22	0.70	1775	8760	23995.8	**12.00**	Manuf. Data
SOx	5.88E-04	0.002	1775	8760	64.7	**0.03**	AP-42, Table 3.2-2
PM10	7.71E-05	0.0002	1775	8760	8.5	**0.00**	AP-42, Table 3.2-2
CO2e	108.5	348	1775	8760	1362.4	**5967.4**	GHG Subpart C Calc
HAPs							
HCHO*	0.03	0.10	1775	8760	3290.9	**1.65**	Manuf. Control Data
Benzene	4.40E-04	0.001	1775	8760	48.4	**0.024**	AP-42, Table 3.2-2
n-Hexane	1.11E-03	0.004	1775	8760	122.1	**0.061**	AP-42, Table 3.2-2
Acetaldehyde	8.36E-03	0.027	1775	8760	919.9	**0.460**	AP-42, Table 3.2-2

***Claiming 35% destruction efficiency for CO, and 76% efficiency for HCHO for the oxidation catalyst.**

Cottonwood Wash Compressor Station
Heater / Boiler Detail Sheet

			Elevation:	4950 ft asl
Source ID Number	**REBLR-2**	Source Location	Zone:	12
Source Description	TEG Reboiler		UTME:	630800
Equipment Usage			UTMN:	4428200
Equipment Make		Potential operation		8760 hr/yr
Equipment Model				
Serial Number				
Date in Service	5/9/2005	Potential fuel usage		11 MMscf/yr
Equipment Configuration				1262 scf/hr
Emission Controls				
		Stack ID		**REBLR-2**
		Stack Height		25 ft
Fuel Heating Value	1109 Btu/scf	Stack Diameter		12.5 in
Heat Rate	1.4 MMBtu/hr	Exit Velocity		21.5 ft/s
		Exit Temperature		400 deg F
		Volume Flow Rate		1100 ft³/min

Potential Emissions

Pollutant	Emission Factor (lb/MMscf)	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx	100	1.4	8760	0.13	0.55	AP-42 Table 1.4-1
CO	84	1.4	8760	0.11	0.46	AP-42 Table 1.4-1
VOC	5.5	1.4	8760	0.007	0.03	AP-42 Table 1.4-2
SOx	0.6	1.4	8760	0.001	0.003	AP-42 Table 1.4-2
PM10	7.6	1.4	8760	0.010	0.04	AP-42 Table 1.4-2
HCHO	0.75	1.4	8760	0.001	0.004	AP-42 Table 1.4-2

CO2e Emission Calculations

Conversions:

1 Metric Ton = 2204.62 lbs

1 kg = 0.001 metric tons

Pollutant	kg/mmbtu	metric ton	tpy
CO_2	53.02	650	717
CH_4	0.001	0	0
N_2O	0.0001	0	0
		CO_{2e} =	717

$CO_{2e} = CO_2 + (CH_4*21) + (N_2O*310)$

Cottonwood Wash Compressor Station
Dehy Vent Detail Sheet

			Elevation:	4950 ft asl
Source ID Number	**DEHY-LO**	Source Location	Zone:	12
Source Description	Glycol Dehydrator		UTME:	630800
Equipment Usage			UTMN:	4428200
Equipment Make		Potential operation		8760 hr/yr
Equipment Model				
Serial Number				
Date in Service	5/9/2005			
Equipment Configuration	TEG Dehy			
Emission Controls	NA			

Permit Status	Part 71 Pending

Source ID Number	DEHY-LO
Source Description	Glycol Dehydrator

GRI Glycalc Inputs

Annual Hrs of Operation	8760	(<= 8760 hr/yr)
Type of Glycol Used	TEG	(EG, TEG, DEG)
Wet Gas Temperature	80	deg F
Wet Gas Pressure	780	psig
Wet Gas Water Content	Saturated	lb H20/MMscf or Saturated
Dry Gas Flow Rate	80	MMscf/day
Dry Gas Water Content	7	lb H20/MMscf (or # absorber stages)
Glycol Recirc.	18	gal / # water
Pump Type	Electric	Electric / G @ 1.5% H20 -- Default
Gas Pump Volume Ratio	N/A	acfm gas / gpm glycol
Flash Tank Present?	Y	(Y/N)
Flash Tank Temperature	160	deg F
Flash Tank Pressure	45	psig
Stripping Gas Used	None	(None, Dry Gas, Flash Gas, Nitrogen)
Stripping Gas Flow Rate	N/A	scfm
Condenser Present?	Y	
Condenser Temperature	140	deg F
Condenser Pressure	12.5	psig

Cottonwood Wash/West Compressor Station
Fugitive VOC's Detail Sheet

Source ID Number	FUG	SCC	31088802
Equipment ID		Source Location Zone:	
Source Description	Piping Fugitives	Horizontal:	
		Vertical:	
		Potential operation	8760 hr/yr
		Previous operation	8760 hr/yr
		Current operation	8760 hr/yr
Date in Service	1996		
Permit Status	Awaiting		

Potential Emissions

Pollutant	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
VOC	8760	2.78	12.18	OAQPS TTN BBS
HAP	8760	0.19	0.84	

Calculation Methodology

Equipment Type	Emission Factor (lb/hr/source)	Source Count	Percent VOC	Hours of Operation	Percent HAP	Uncontrolled Emissions Total HAP Emission Rate (tpy)	Total VOC Emission Rate (tpy)
Valves-Gas/Vapor	0.009920	942	10.40%	8760	0.12%	0.05	4.26
Valves-Light Liquids	0.005500	221	99.00%	8760	11.40%	0.61	5.27
Valves-Heavy Liquids	0.000019			8760		0.00	0.00
Relief Valves	0.019400	61	10.40%	8760	0.12%	0.01	0.54
Compressor Seals	0.019400	12	10.40%	8760	0.12%	0.00	0.11
Pump Seals-Light Liquids	0.028660	8	99.00%	8760	11.40%	0.11	0.99
Pump Seals-Heavy Liquids	0.001130			8760		0.00	0.00
Sample Connections	0.000243			8760		0.00	0.00
Open-Ended Lines	0.004410	4	10.40%	8760	11.40%	0.01	0.01
Flanges-Gas/Vapor	0.000860	1603	10.40%	8760	0.12%	0.01	0.63
Flanges-Light Liquids	0.000243	359	99.00%	8760	11.40%	0.04	0.38
Flanges-Heavy Liquids	0.000001			8760		0.00	0.00
Totals						0.84	12.18

[1] Oil and Gas Production Operations equipment leak emission factors (from OAQPS TTN BBS) EPA 453/R-95-017 Table 2-4, Nove

Ambient Air Quality Impact Analysis

Air Quality Impact Qualitative Analysis

There are two ambient air quality monitors within the Basin that monitor ozone and nitrogen dioxide (NO2). Results of the two monitors (Site ID 49-047-2002 – near Redwash and Site ID 49-047-2003 – near Ouray) are summarized below:

SITE ID #	YEAR	POLLUTANT	1st MAX	2nd MAX	3rd MAX	4th MAX
49-047-2002	2009	NO2 – 1-hr	19	16		
	2010	NO2 – 1-hr	55	41		
	2009	O3 – 1-hr	63	62	61	60
	2010	O3 – 1-hr	120	114	111	108
	2009	O3 – 8-hr	60	58	58	56
	2010	O3 – 8-hr	105	103	99	88
49-047-2003	2009	NO2 – 1-hr	12	10		
	2010	NO2 – 1-hr	56	40		
	2009	O3 – 1-hr	66	66	62	62
	2010	O3 – 1-hr	139	131	131	130
	2009	O3 – 8-hr	61	60	57	57
	2010	O3 – 8-hr	123	122	122	117

***concentrations are in ppb**

The monitoring data suggests that the area is of lesser concern for NO2 emissions since the highest recorded concentration in the two monitoring years was just slightly above 50% of the standard. While the table does not show the annual NO_2 monitoring values, they are well below the standard. This facility has been operating since 1996, and therefore the associated emissions should already be represented in the existing monitoring data.

The monitoring data does show elevated ozone concentrations in 2010. While there is concern with the winter time ozone issues, the area is listed as unclassifiable. Again, this facility has been operating since 1996, and therefore the associated emissions should already be represented in the existing monitoring data.

Environmental Impact Statement: In March of this year the Final Environmental Impact Statement (FEIS) for the Greater Natural Buttes area. Modeling was done as part of the EIS. While this is not a regulatory modeling exercise, it does give an indication of the air quality in the area. NO2, SO2 and summertime O3 were modeled. Attached is the air quality excerpt out the FEIS. The modeling indicates compliance with all NAAQS and increment standards. The modeled concentrations indicate compliance with the ozone standard during the summer months

4.0 Environmental Impacts

This chapter presents discussions of the environmental impacts associated with the Proposed Action and the alternatives presented in Chapter 2.0. Disturbance comparisons for these alternatives are presented in **Table 2.10-1**, thus providing the reviewers and the decision maker a side-by-side comparison of the potential alternatives for each key resource topic. Analysis of environmental impacts in this chapter is confined to that associated with new disturbances for each alternative. To estimate the total impacts for each action alternative, the impacts for the No Action Alternative must be added to the impacts for each alternative. Many of the effects identified as a result of oil and gas development occurring under the No Action Alternative also would occur under expanded oil and gas activities associated with implementation of the Proposed Action or other action alternatives. Differences among the action alternatives generally would be in the degree or level of effects. Expansion of the existing oil and gas field would create effects that overlap or combine with those occurring under the No Action Alternative. These effects are analyzed in detail in Chapter 5.0, Cumulative Effects.

It should be noted that final well siting and associated site-specific effects would be determined in detail during the APD phase of the permitting process. Under this process, each well would undergo additional biological, cultural, and paleontological evaluation prior to construction, as directed by the BLM (Section 2.3, Management Common to All Alternatives). Additional site-specific mitigation requirements also may be added at that time. The environmental impacts identified in this EIS are based on general well locations as discussed in Chapter 2.0 of this document.

Planned natural gas developments in the GNBPA under the No Action Alternative are described in previously approved NEPA documents identified in Section 2.4.1. As of October 2007, there were 1,102 undrilled wells within the GNBPA that have been described in approved NEPA decision documents or identified in the UDOGM database. As of October 2007, UDOGM data indicated that 584 federal wells, 192 State of Utah wells, 9 wells on Indian lands, and 9 wells on private lands had approved APDs or were actively drilling within the GNBPA.

4.1 Air Quality

The purpose of the air quality analysis was to assess local and regional air quality impacts from current and future reasonably foreseeable development in the Uinta Basin Region, in conjunction with the proposed project. The general approach was to develop an emissions inventory for a "project base year" (defined below) to tabulate emissions and conduct modeling.

The air quality analysis incorporated the planned development and a prepared set of emissions data for project modeling, including project development alternatives and reasonably foreseeable development as discussed below. Those emissions data were incorporated into the modeling system for the project base year, and used to predict potential impacts on visibility, acid deposition, and air quality, including ozone. The analysis identifies potential impacts on resources evaluated, and characterizes the major source or source groups that contribute to those impacts.

The 2006 emissions data was used as the basis for comparing emissions and impacts for the base year. This selection was made to coincide with the 2006 Western Regional Air Partnership (WRAP) Phase III emissions inventory for the Uinta and Piceance basins, which was developed by a collection of government and industry stakeholders for ozone modeling in the same area. As such, these data serve as the best available data for base year emissions and comparisons.

Emissions of criteria pollutants and source characteristics for the proposed project alternatives were based on project data provided by KMG. To support the modeling effort, emissions scenarios were developed for the base year and 3 forecast years and included reasonably foreseeable development, the proposed project, and maximum production. Emissions inventories were developed for each of the following scenarios:

- 2006 Baseline – 2006 base year actual emissions;
- 2018 Projected Baseline – 2018 projected emissions without the proposed project;
- 2017 Proposed Action Alternative – 2018 Projected Baseline emissions with project emissions from the proposed alternative in 2017; and
- 2026 Optimal Recovery Alternative – 2018 Projected Baseline emissions with project emissions from the maximum recovery development alternative in 2026.

The 2018 Projected Baseline essentially is the No Action Alternative, but also includes non-project emissions. The Resource Protection Alternative focuses on minimizing land disturbance for the installation and operation of wells and other support facilities. From an air emissions perspective, ambient impacts from the Resource Protection Alternative are well-characterized by the impacts from the Proposed Action. For that reason, the Resource Protection Alternative was not modeled as a separate evaluation.

The 2018 Projected Baseline was used as the baseline for the Optimal Recovery Alternative, though peak production under this alternative is anticipated in 2026. This approach provides a consistent basis of comparison between the alternatives and reduces uncertainty in baseline emissions from projecting development beyond the WRAP inventory time horizon.

The 2018 Projected Baseline does not include estimates of emissions from existing evaporation ponds in the GNBPA. However, the emissions from these ponds are conservatively estimated to be 45 tpy VOC and 39 tpy HAP. The estimated VOC levels for the evaporation ponds are less than 0.1 percent of the VOC emissions for the projected baseline emissions used in ozone modeling (see Appendix G).

GHGs are produced and emitted by various sources during phases of oil and gas exploration, well development, and production. The primary sources of GHGs associated with oil and gas exploration and production are CO_2, N_2O, and CH_4. In addition, volatile organic compounds (VOCs) are a typical source of emissions associated with oil and gas exploration and production. Under specific environmental conditions, N_2O and VOCs form ozone, which also is considered a GHG.

Climate change analyses are comprised of several factors including, but not limited to, GHGs, land use management practices, and the albedo effect. While emissions from oil and gas activities may contribute to the effects of climate change to some extent, it currently is not possible to associate any of these particular actions with the creation of any specific climate-related environmental effects. The tools necessary to quantify climatic impacts presently are unavailable. As a consequence, impact assessment of specific effects of anthropogenic activities cannot be determined. Additionally, specific levels of significance have not yet been established. Therefore, climate change analysis for the purpose of this document ***focuses on*** accounting and disclosing of GHG emissions that may contribute to climate change ***(see Section 3.1.3.7 for text acknowledging related potential impacts)***.

Emissions Data Development

Emissions data for the Proposed Action and the Optimal Recovery Alternative were developed from available emission factors, analytical data, applicable ***ACEPMs (Appendix A)***, applicant-provided equipment specifications, and anticipated activity levels. Emission rates were developed for the criteria pollutants and for selected HAPs. A summary of criteria pollutant emissions from stationary sources in the Uinta Basin is provided in **Table 4.1-1**, and the project-related increases in the major components of HAPs for the Proposed Action and Optimal Recovery Alternative are provided in **Table 4.1-2**. Emissions for a full list of HAPs were reviewed, but only those with the greatest emissions in relation to health effects were evaluated. A summary of emission calculation methods for each source type and pollutant is shown in **Table 4.1-3**.

Table 4.1-1 Summary of Criteria Pollutant Emissions for Each Scenario

Criteria Pollutant	Emissions (tpy)					
	2006 Baseline	2018 Projected Baseline	2017 Proposed Action		2026 Optimal Recovery Alternative	
			Project	Total	Project	Total
NO_X	10,754	10,138	2,***213***	12,***351***	4,946	15,084
CO	7,800	9,732	**1,300**	**11,032**	2,994	12,726
SO_2	391	30	25	55	78	108
PM_{10}	592	565	***1,011***	1,***576***	2,658	3,223
VOC	70,226	184,262	6,***617***	190,***879***	24,976	209,238

Source: Air Quality Technical Support Document (**Appendix G**).

Table 4.1-2 Summary of Potential Increases in Emissions of HAPs for Project-related Alternatives

Pollutant	Potential HAP Increase (tpy)	
	Proposed Action Alternative	Optimal Recovery Alternative
Benzene	67.***0***	255.2
Toluene	**172.4**	662.1
Ethyl Benzene	12.7	48.5
Xylenes	**185.7**	714.1
Formaldehyde	***71.3***	156.5
n-Hexane	**194.9**	748.5

Source: Air Quality Technical Support Document (**Appendix G**).

Table 4.1-3 Summary of Emissions Calculation Methods by Source Type and Pollutant

Source Type	Pollutant	Emissions Calculation Methodology
Drill Rig Engines	NO_X	40 CFR 1039.101
	CO	***Tier 2 – Near-field Impact Analysis***
	VOC	***Tier 4 – Near-field Impact Analysis and Regional Emissions***
	$PM/PM_{10}/PM_{2.5}$	
	SO_2	Mass balance of fuel sulfur (15 ppm weight [ppmw] fuel sulfur)
	HAP	National Mobile Inventory Model Database (USEPA 2005)
Drill Rig Boilers	All	USEPA AP-42 Volume I: Stationary Sources *Chapter 1.3* (USEPA 1998***b***)
Drilling and Completion Traffic	NO_X	USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
	CO	
	VOC	
	$PM_{10}/PM_{2.5}$	USEPA AP-42 Volume I *Chapter 13.2.2* (USEPA 2006) and USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
	SO_2	USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
Condensate Flashing	VOC	American Petroleum Institute ***(API)*** E&P Tanks v2.0 based on Analysis of Condensate
	HAP	
Separator Heaters	NO_X	USEPA AP-42 Volume I: Stationary Sources *Chapter 1.4* (USEPA 1998***c***)
	CO	
	VOC	
	$PM/PM_{10}/PM_{2.5}$	
	SO_2	Mass balance of fuel sulfur [20 ppmw fuel sulfur]
	HAP	USEPA AP-42 Volume I: Stationary Sources *Chapter 1.4* (USEPA 1998***c***)
Production Well Fugitives	VOC	USEPA Protocol for Equipment Leak Estimates (USEPA 1995b)
	HAP	Mass fraction of VOC based on Analysis of Condensate
Production Traffic	NO_X	USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
	CO	
	VOC	
	$PM_{10}/PM_{2.5}$	USEPA AP-42 Volume I *Chapter 13.2.2* (USEPA 2006) and USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
	SO_2	USEPA AP-42 Volume II: Mobile Sources (USEPA 1995a)
Produced Water Tank Batteries	VOC	TANKS 4.09 based on Analysis of Condensate
	HAP	Mass Fraction of VOC based on Analysis of Condensate
Gas-fired Compression Engines	NO_X	Engine Manufacturer Specifications
	CO	
	VOC	
	$PM_{10}/PM_{2.5}$	USEPA AP-42 Volume I: Stationary Sources *Chapter 3.2* (USEPA 2000)
	SO_2	Mass balance of fuel sulfur [20 ppmw fuel sulfur]
	HAP	USEPA AP-42 Volume I: Stationary Sources *Chapter 3.2* (USEPA 2000)

Source: Air Quality Technical Support Document (**Appendix G**).

The air quality model AERMOD was used to evaluate impacts on air quality in the near-field. Several scenarios, including various well spacing and drill density plans, were evaluated to determine their projected impacts on the near-field. A square mile area was used to characterize the scenario sources arrangement, and impacts were calculated within that area and at the boundary of the square mile area. For drilling operations, it was assumed that ***up to four*** drill rig***s*** would operate in this area at any one time. ***Annual impacts from drilling operations were based on the assumption that 64 wells could be drilled in a square mile to accommodate the proposed 10-acre downhole spacing.*** For operations, the source arrangement depicted wells located on a 10-, 20-, and 40-acre spacing. For compression, a single compressor station was sited in the area and impacts were calculated in the near-field.

The CALPUFF modeling system was used to estimate impacts on visibility (regional haze), air quality, and acid deposition in areas 50 kilometers (km) or more from the development area. The Models-3 Community Multiscale Air Quality (CMAQ) model was used to evaluate impacts on ambient air ozone in the region.

An inventory of actual emissions developed specifically for this analysis were input to the AERMOD and CALPUFF models to analyze compliance with the NAAQS and evaluate impacts to regional haze, acid deposition, and acid neutralizing capacity at sensitive lakes in Class I areas. Comparison of impacts to PSD increments is provided for informational purposes only; this study does not represent a PSD increment-consumption analysis. The inventory for the CMAQ ozone modeling utilized actual project base year emissions along with emissions from other sources (i.e., electric generation, motor vehicles, and biogenics).

The CAA lists HAPs that could be emitted during project operations: primarily BTEX (benzene, toluene, ethyl benzene, and xylene) from the well dehydrators and formaldehyde from the pipeline compressor engines. Control of these and other HAPs would be achieved through compliance with applicable MACT standards. HAP emissions for each activity were developed on a per unit basis and were based on approved emissions factors, mass balance, or process simulation, where appropriate. Site-specific supporting information such as operation schedules, equipment specification, and physical and chemical properties of fuel and materials were used to develop the emissions inventory for the various alternatives. Where site-specific information was not available, the analysis used published references or assumptions based on professional experience as described in the Technical Support Document (**Appendix G**).

NESHAP and MACT regulations for oil and natural gas production facilities include provisions for ethylene glycol dehydrators and vents, storage vessels with flash emissions, and ancillary equipment. Under these provisions, any source that emits or has the potential to emit 10 tpy or more of any HAP is considered a major source; would require an operating permit under Title V of the CAA; and must install and operate control equipment to control air emissions. Under these same provisions, glycol dehydration units emitting less than 1 tpy benzene are considered "small," and would not require controls under MACT rules.

Ambient air concentrations of HAPs were determined based on these emissions rates using the same AERMOD model scenarios used for near-field criteria pollutant analysis. These ambient concentrations were compared to the USEPA Toxic Screening Levels (TSLs) to determine if any adverse impact would be predicted from project-related source emissions.

Based on the minimal content of hydrogen sulfide (H_2S) in the natural gas found in the GNBPA, potential H_2S impacts would be negligible. However, should H_2S be encountered, operations on federal or Indian leases would be regulated by Onshore Oil and Gas Order No. 6 (Hydrogen Sulfide Operations). This order requires monitoring of H_2S beginning at levels of 10 ppm at each drilling well (40 CFR part 63, subpart HH §63.760[b][1] through [4]; and 40 CFR part 63, subpart A of the General Provisions, effective June 17, 1999). Should H_2S levels increase, specific drilling and production equipment, along with drilling and public protection plans, would be required ***under Onshore Order No. 6 in zones where H_2S can reasonably be expected to be present at concentrations of 100 ppm or more.***

The analysis was based on several conservative assumptions, including:

- Maximum measured and/or estimated background criteria air pollutant concentrations were assumed to occur at all locations in the region throughout the life of the project.
- All existing emissions sources were assumed to operate at their reasonably foreseeable emission rates simultaneously throughout the life of the project. Given the number of sources included in this analysis, the probability of such a scenario actually occurring over an entire year (or even 24 hours) is small. While this assumption is typically used in modeling analyses, the resulting predicted impacts would be overstated.
- For the near-field modeling, total predicted short-term air pollutant impact concentrations were assumed to be the sum of the first maximum background concentration, plus the maximum modeled

concentrations, which actually would occur under very different meteorological conditions and would not be likely to coincide.

- The HAP analyses assumed all existing equipment would continue to operate simultaneously at the assumed emission levels continuously throughout the life of the project. ***Since no data are available to characterize HAP concentrations in the vicinity of the GNBPA, no background HAP concentrations were assumed for near-field modeling.***

4.1.1 No Action Alternative

On BLM-administered lands, current management plans would continue to guide oil and natural gas exploration and development activity. Air quality effects for the No Action Alternative would include an increase in air pollutant emissions resulting from drill and development projects previously approved.

Emissions for the No Action Alternative are represented by the 2018 Projected Baseline, specifically including the WRAP III data for the Uinta and Piceance basins, and the WRAP II data for other basins.

4.1.1.1 Impacts on Air Quality

The USEPA dispersion model AERMOD was used to predict maximum potential near-field air quality impacts from existing emission sources, which would continue to operate under the No Action Alternative. As of October 2007, there were 1,102 undrilled wells within the GNBPA that have been described in approved NEPA decision documents or identified in the ***UDOGM*** database. The analysis results identify predicted air pollutant concentrations in the vicinity of ***producing*** wells ***(drill rigs),*** compressor engines, ***and related oil and gas facilities. Specific modeling scenarios for the near-field impact analysis are discussed in more detail in Appendix G.***

CALPUFF modeling was used to predict impacts at distant ***receptors*** (greater than 50 km from the GNBPA), mandatory federal PSD Class I areas for comparison with applicable air quality standards, PSD increments, HAP exposures, visibility standards, and atmospheric deposition (**Appendix G**).

Because this alternative includes wells that have not yet been drilled, there would be construction-related air quality impacts. Construction emissions would occur during road and well pad construction, well drilling, and well completion testing. In addition, particulate matter ($PM_{2.5}$ and PM_{10}) concentrations likely would increase during construction. Potential SO_2 emissions would be generated by drilling rigs and other diesel engines used during rig-up, drilling, and completion operations (sulfur being a trace element in diesel fuel). Maximum air pollutant emissions from each well would be temporary (i.e., occurring only during the construction period), would occur in isolation, and would not significantly interact with adjacent well locations. Since construction emissions would be temporary, PSD increments are not applicable.

Near-field modeling was conducted to determine the impacts from simultaneous operation of drill rigs on adjacent pads spaced at 400-meter intervals. This modeling assumed drill rigs (each with two drill rig engines and one rig boiler) operating simultaneously on each of four adjacent pads. Both Tier 2 and Tier 4 drill rig engines were modeled, with the data shown separately in Table 4.1-4. Modeling for the single completion rig engine on four adjacent pads was conducted separately and showed lower impacts than the scenario with four drill rigs.

The maximum impacts of criteria pollutants in the near-field for this alternative are presented in Table 4.1-4. As shown in Table 4.1-4, the near-field modeled impacts would be in compliance with the NAAQS.

Table 4.1-4 Air Quality Impacts for Criteria Air Pollutants in the Near-field, No Action Alternative

Pollutant	Standard	Modeled Impact[1] (µg/m³)	Background Concentration (µg/m³)	Total Impact (µg/m³)	NAAQS / SAAQS (µg/m³)
NO_2	*1-hour*[2]	*137.1 (106.9)*	*N/A*[3]	*157.2 (125.6)*	*188*
	Annual[4]	*7.7 (2.0)*	*9.0*	*16.7 (11.0)*	100
CO	1-hour	*399*	6,325	6,*724*	40,000
	8-hour	*251*	3,910	4,*161*	10,000
SO_2	*1-hour*[5]	*2.6*	*21.7*	*24.3*	*196*
	3-hour	*1.9*	*16.7*	*18.6*	1,300
	24-hour	*0.9*	*5.9*	*6.8*	365
	Annual	*0.1*	*1.5*	*1.6*	80
PM_{10}	24-hour	*4.5 (0.7)*	*18*	*22.5 (18.7)*	150
$PM_{2.5}$	24-hour	*4.5 (0.7)*	*21.6*	*26.1 (22.3)*	35
	Annual	*0.0 (0.0)*	*12.3*	*12.3 (12.3)*	15

[1] *Modeled results are based on Tier 2 engine emission factors; results in parentheses reflect Tier 4 engine emission factors.*

[2] *Modeled impacts are the 5-year average 98th percentile daily maximum.*

[3] *1-hour NO_2 modeling used background concentrations that vary by season and hour of day.*

[4] *For annual averaging period, predicted concentration does not include a reduction from NO_X to NO_2. All NO_X is presumed to be NO_2.*

[5] *Modeled impacts are the 5-year average 99th percentile daily maximum.*

Source: Air Quality Technical Support Document (Appendix G; *Tables 5-11, 5-12, and 5-13*).

Comparison of modeled HAP concentrations against USEPA TSLs and Reference Concentrations (RfC) indicates no adverse impacts from emissions of HAPs from project sources. The maximum concentrations are predicted from the 10-acre production scenario (64 operating wells per section) for all pollutants. These results are shown in Table 4.1-5.

Table 4.1-5 Air Quality Impacts for HAPs in the Near-field, No Action Alternative

Pollutant/Averaging Period	*Concentration per Production Well Density (µg/m³)*			*Non-Carcinogenic RfC*[1] *(µg/m³)*	*TSL*[2] *(µg/m³)*
	10-Acre Spacing	*20-Acre Spacing*	*40-Acre Spacing*		
Benzene					
24-hour	*5.25*	*4.14*	*2.99*	-	*53.3*
Annual	*1.55*	*1.22*	*0.71*	*30*	-
Ethylbenzene					
24-hour	*0.32*	*0.26*	*0.18*	-	*14,473*
Annual	*0.17*	*0.13*	*0.08*	*1,000*	-

Table 4.1-5 Air Quality Impacts for HAPs in the Near-field, No Action Alternative

Pollutant/Averaging Period	Concentration per Production Well Density (µg/m³) 10-Acre Spacing	20-Acre Spacing	40-Acre Spacing	Non-Carcinogenic RfC[1] (µg/m³)	TSL[2] (µg/m³)
Formaldehyde					
24-hour	3.89	3.76	3.76	-	37
Annual	0.85	0.64	0.50	9.8	-
n-Hexane					
24-hour	14.85	11.70	8.45	-	5,875
Annual	4.47	3.52	2.05	700	-
Toluene					
24-hour	12.17	9.59	6.93	-	2,512
Annual	3.63	2.86	1.67	5,000	-
Xylene					
24-hour	9.08	7.15	5.16	-	14,473
Annual	2.68	2.11	1.23	100	-

[1] USEPA Air Toxics Database, Table 1 (USEPA 2010b).

[2] Utah Division of Air Quality (UDAQ) Air Toxic Modeling Guidance for TSLs (UDAQ 2010).

Source: Air Quality Technical Support Document (Appendix G).

4.1.1.2 Impacts at Class I and II Areas – Acid Deposition

The CALPUFF model system post-processor, CALPOST, provided acid deposition results for nitrate and sulfate deposition at Class I and sensitive Class II areas, which were then used to analyze impacts to the acid neutralizing capacity of selected sensitive lakes in the modeling domain. Modeled deposition values from the No Action Alternative, which consists of non-project emission sources including other oil and gas projects, were shown to contribute 4.955 kilograms per hectare-year (kg/ha-year) for nitrogen at Mesa Verde National Park. This is above the USFS-established comparative deposition value of 3 kg/ha-year.

The maximum acid deposition rate at the listed Class II areas in the region is predicted at the Holy Cross Wilderness Area. The maximum deposition from the No Action Alternative would be 2.602 kg/ha-year of nitrogen.

4.1.1.3 Impacts at Class I and II Areas – Visibility

The CALPUFF model system was used to evaluate impacts on visibility at the Class I areas and at the listed sensitive Class II areas. The results of the CALPUFF analysis showed that existing, approved, and proposed emissions sources that constitute the No Action Alternative would have recognizable visibility impacts greater than 10 percent increase in the light extinction coefficient (1.0 dv; eighth highest, Method 6) at listed Class I areas. All Class I areas in the region would be impacted for more than 223 days a year at the 1.0-dv level. At Arches National Park, the non-project related sources would contribute to visibility impacts greater than the 1.0 dv threshold for 311 days a year.

The CALPUFF modeling indicated that the No Action Alternative emissions would cause impacts at the 1.0-dv level for at least 201 days a year at the Class II areas. However, the FLM guidance provides no visibility threshold of concern for Class II areas.

4.1.1.4 Impacts on Ambient Ozone Levels

The CMAQ modeling system was used to estimate impacts on ambient air ozone levels from the emissions for 2006, representative of the base year operations. Results from that modeling effort were compared to actual monitored levels in the region (though not directly in the GNBPA). A formal Model Performance Evaluation (MPE) was conducted for 2006, which was used to evaluate the performance of the model with actual conditions, and to provide an adjustment of modeled impacts for future development scenarios. The MPE showed that the modeling system meets the USEPA-established criteria for acceptable model accuracy and error statistics at the existing monitoring stations within the modeling domain. The lack of concurrent ***monitored ozone*** data ***for 2006*** prevents validation and calibration of the model results; however, the model does provide a means to compare the relative change in ambient ozone concentration between the project alternatives and baseline air quality.

The CMAQ modeling system was used to model impacts for 2018 for the projected No Action Alternative, the Proposed Action, and the Optimal Recovery Alternative. The results were used to show the expected change in ozone levels at receptors in the region resulting from each of the alternatives as well as the cumulative impact from expected development. The model results showed no impacts above the current ozone standard of 75 ppb for the fourth highest annual level in the Uinta Basin for the No Action Alternative.

As shown in Section 3.1.2 and Figure 3.1-2, ozone levels monitored at the Ouray and Redwash monitoring stations in the Uinta Basin, showed numerous days during the winter of 2009-2010 and again in the winter of 2010-2011 with 8-hour concentrations above 75 ppb, the current ozone level that forms the basis for the standard. However, the 8-hour average ozone levels monitored during both of the summer episodes were below the 75 ppb level, which is consistent with the modeling results. The ability of current photochemical models to replicate winter ozone formation has not been established. Therefore, the comparison of modeled values to isolated winter values is not appropriate.

The No Action Alternative would involve continued development in the GNBPA as disclosed in approved NEPA decision documents. Given a continued level of NO_X and VOC emissions, and the current levels of ozone observed in the winter, there likely would be continued observations of winter ozone concentrations above the NAAQS resulting from this alternative.

4.1.1.5 Summary of GHG Emissions

GHG were estimated using the *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* (API 2004) as implemented using the SANGEA™ software tool published by the API. The SANGEA™ software tool is an Excel™ macro that uses the calculation methodologies described in the *Compendium* to calculate GHG emissions using a series of modules for different source types. These modules determine the emissions of CO_2, CH_4, and N_2O as well as the global warming potential (GWP) in CO_2e based on the comparative GWP of each GHG species. For this analysis, the default GWP coefficients for CH_4 (21) and N_2O (310) were used. These coefficients were multiplied by the calculated mass emission rate to determine the GWP.

Indirect GHG emissions include additional emissions that occur upstream of the project as a direct result of the increased activity resulting from the proposed alternatives. Additional annual electricity use for all project alternatives would increase significantly due to the installation of electric compression engines. Total annual electricity consumption was based on additional electric compression. Emission factors for GHG from electricity production vary by region since the means of power production and fuel characteristics vary by region. GHG emissions for electricity consumption for this analysis were based on the Utah-produced factors as provided in SANGEA™. Detailed emission rates by source and pollutant type are provided in **Table 4.1-6**.

Regulatory Analysis

Regulatory Analysis

40 CFR 52 – Prevention of Significant Deterioration (PSD)

Subpart A, General Provisions describe general requirements for pre-construction review and permitting for major sources under the PSD program. Based on the potential to emit of the Facility, the Cottonwood Compressor Station is a not PSD major source and the regulations are therefore not applicable.

40 CFR 60 - New Source Performance Standards (NSPS)

Subpart A contains general requirements for notification, testing and reporting for the NSPS program. The subpart applies to each facility that has an affected source as defined under another subpart. The facility is subject to 40 CFR part 60, subpart JJJJ; therefore, the General Provisions of part 60 do apply.

Subpart Db, Standards of Performance for Small Industrial, Commercial, Institutional Steam Generating Units, applies to steam generating units having a capacity greater than 100 MMBtu/hr that are construction, reconstructed or modified after June 9, 1989. No heater located at the facility is rated greater than 100 MMBTU/hr, therefore, NSPS Subpart Db is not applicable.

Subpart Dc, Standards of Performance for Small Industrial, Commercial, Institutional Steam Generating Units, applies to steam generating units having a capacity between 10 MMBtu/hr and 100 MMBtu/hr that are construction, reconstructed or modified after June 9, 1989. A steam generating unit is defined, by rule, as follows:

> *"Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart."*

No heater located at the facility is rated at greater than 10 MMBTU/hr, therefore, NSPS Subpart Dc is not applicable.

Subpart K, Standards of Performance for Storage Vessels for Petroleum Liquids for Construction, Reconstruction, or Modification Commenced after June 11, 1973, and Prior to May 19, 1978. The storage vessels at the facility were constructed after May 19, 1978; therefore, NSPS Subpart K is not an applicable regulation for the Facility.

Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids for Construction, Reconstruction, or Modification Commenced after May 1, 1978, and Prior to July 23, 1984. The storage vessels at the Facility were constructed after July 23, 1984; therefore, NSPS Subpart Ka is not an applicable regulation for the Facility.

Subpart Kb, Standards of Performance for VOL Storage Vessels, regulating volatile organic liquid storage vessels having a storage capacity greater than 75 m^3 (19,815 gallons), constructed after July 23, 1984. VOL storage vessels at the Facility have a capacity less than 75 m^3 and therefore this subpart is not applicable.

Subpart GG, Standards of Performance for Turbines –applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired and constructed, modified, or reconstructed after October 3, 1977. There are micro turbines but do not exceed 10MM BTU/hr at the Facility therefore this subpart is not applicable.

Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, applies to affected facilities in onshore natural gas processing plants. The Facility is not a natural gas processing facility, as defined in §60.631; therefore, this subpart is not applicable.

Subpart LLL, Standards of Performance for Onshore Natural Gas Processing: SO2 Emissions, applies to facilities that process natural gas and have sweetening units. The Facility is not a natural gas processing facility and does not have a sweetening unit; therefore, NSPS Subpart LLL is not an applicable regulation at the current time.

Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, this subpart applies to affected facilities in the synthetic organic chemicals manufacturing industry. The Facility is not, by rule definition, a synthetic organic chemical manufacturing facility. Therefore, NSPS Subpart VV is not an applicable regulation.

Subpart IIII, Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines, applies to manufacturers, owners, and operators of stationary compression ignition internal combustion engines. There are no CI engines installed at the facility at this time; therefore, NSPS Subpart IIII is not an applicable regulation for The Facility.

Subpart JJJJ, Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines, applies to manufacturers, owners, and operators of stationary SI internal combustion engines. There are SI internal combustions engines that were manufactured after July 1, 2007; therefore, NSPS Subpart JJJJ is applicable to The Facility.

Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. This subpart establishes emissions standards and compliance schedules for the control of VOCs and SO2 emissions from affected facilities that commenced construction, modification or reconstruction after August 23, 2011.The rule applies to compressors located between the well head and the city gate. The CWW-WST 5 and 6 engines were installed after August 23, 2001 but were relocated Anadarko's Luke Gus Compressor station and, therefore, are not subject to this rule.

40 CFR 61 - National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart V, National Emission Standard for Equipment Leaks (Fugitive Emission Sources) applies to sources that are intended to operate in volatile hazardous air pollutant (VHAP) service. Engineering judgment based on the gas composition and process knowledge demonstrates that the percent VHAP content can be reasonably expected never to exceed 10 percent by weight; therefore Subpart V is not an applicable regulation for The Facility.

40 CFR 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A contains general requirements for notification, testing and reporting for the NESHAP program. The subpart applies to each facility that has an affected source as defined under another subpart. As The Facility will have units subject to one or more standards under Part 63, Subpart A applies to the facility.

Subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, applies to glycol dehydration units, storage vessels with potential for flash emissions, and ancillary equipment operating in volatile hazardous air pollutant service that is located at a natural gas processing plant which is a major source of HAP's. The Facility is not a natural gas processing plant therefore Subpart HH is not an applicable to the facility.

Subpart HHH, National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. The Facility is not a transmission or storage facility therefore Subpart HHH does not apply.

Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), establishes national emission limitations, operating limits, and work practice standards for organic hazardous air pollutants emitted from organic liquids distribution (non-gasoline) operations at major sources of HAP emissions. The Facility is not an organic liquids distribution operation; therefore Subpart EEEE is not applicable.

Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE), establishes national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines, and requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations. The Facility does have stationary RICE; therefore Subpart ZZZZ is applicable.

40 CFR 64 – Compliance Assurance Monitoring (CAM)

This regulation applies to a pollutant specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit meets certain criteria. The Facility is a major facility and therefore CAM does apply.

40 CFR 68 – Chemical Accident Prevention

Subpart A contains general requirements for sources that have more than a threshold quantity of a regulated substance in a process and the requirements for a Risk Management Plan (RMP). The Facility is no longer subject to part 68.

40 CFR 82 – Stratospheric Ozone and Climate Protection

Subpart A applies to any person that produces, transforms, destroys, imports or exports a controlled substance or imports or exports a controlled product. The Facility does not conduct any of these activities; therefore this is not an applicable regulation.

Subpart F applies to any person servicing, maintaining, or repairing appliances using ozone depleting substances. This subpart also applies to persons disposing of appliances, including small appliances and motor vehicle air conditioners. In addition, this subpart applies to refrigerant reclaimers, technician certifying programs, appliance owners and operators, manufacturers of appliances, manufacturers of recycling and recovery equipment, approved recycling and recovery equipment testing organizations, persons selling class I or class II refrigerants or offering class I or class II refrigerants for sale, and persons purchasing class I or class II refrigerants. Some small air conditioning appliances are in use at the Facility and therefore Subpart F may be an applicable regulation.

Subpart H Halon Fire Emission Reduction -- applies to any person testing, servicing, maintaining, repairing or disposing of equipment that contains halons or using such equipment during technician training. This subpart also applies to any person disposing of halons; to manufacturers of halon blends; and to organizations that employ technicians who service halon containing equipment. Halon is not used at the facility.

40 CFR 98 – Green House Gas Reporting

Subpart A –General Provisions –applies to a facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(2) in any calendar year starting in 2010 and that emits 25,000 metric tons CO2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this regulation. The Facility does contains stationary fuel combustion sources as defined in Subpart C, however, the GHG emissions for 2011 are estimated to be more than 25,000 metric tons CO2. Therefore, the facility is subject to this subpart.

UNITED STATES DISTRICT COURT
DISTRICT OF COLORADO

Civil Action No.

UNITED STATES OF AMERICA,

Plaintiff,

and the STATE OF COLORADO

Plaintiff-Intervenor

v.

KERR-MCGEE CORPORATION,

Defendant.

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, Plaintiff, the United States of America, (the "United States") on behalf of the United States Environmental Protection Agency ("EPA"), has simultaneously with lodging this Consent Decree filed a Complaint alleging that Kerr-McGee Corporation, or one or more of its wholly-owned subsidiaries, (collectively "Defendant" or "Kerr-McGee" and as more specifically defined below), violated requirements of the Clean Air Act (the "Act") and the federal and state regulations implementing the Act applicable to: (i) five compressor stations referred to herein as the Hudson Facility, Dougan Facility, Frederick Facility, Fort Lupton Facility, and Platteville Facility, which are located in the Denver-Julesburg Basin in and near Adams and Weld Counties, Colorado (the "D-J Basin"), (which facilities are among those later defined as the "D-J Basin Facilities"); and (ii) three compressor stations referred to herein as the Cottonwood Wash Facility, Ouray Facility, and Bridge Station Facility which are in the Uinta Basin located near Vernal, Utah (the "Uinta Basin") (collectively the "Uinta Basin Facilities");

WHEREAS, EPA administers the Act's programs for the Prevention of Significant Deterioration ("PSD"), National Emission Standards for Hazardous Air Pollutants ("NESHAP"), and federal operating permits under Title V with respect to the Uinta Basin Facilities, and the Colorado Department of Public Health and Environment ("CDPHE") as well as EPA, through the Colorado State Implementation Plan ("SIP"), are authorized to administer the PSD, NESHAP, and Title V programs with respect to the D-J Basin Facilities;

WHEREAS, on September 9, 2004, Kerr-McGee disclosed to EPA, pursuant to EPA's policy titled "Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations" published at 65 Fed. Reg, 19,618 - 27 (April 11, 2000), that both the Cottonwood Wash Facility and Ouray Facility, which Kerr-McGee acquired as part of a June 2004 merger with Westport Resources Corporation, had the potential to emit greater than major source thresholds and were subject to the federal operating permit requirements of Title V of the Act. Kerr-McGee subsequently submitted applications for Title V permits for both facilities to EPA, removed the conventional dehydrators at those facilities and replaced them with new "low-emission dehydrators" (as defined herein) incorporating integral vapor recovery capabilities and emitting insignificant amounts of Volatile Organic Compounds ("VOC") or other pollutants regulated under the Act;

WHEREAS, Plaintiff-Intervenor, the State of Colorado ("State"), on behalf of CDPHE, has simultaneously with lodging this Consent Decree, filed a Complaint in Intervention joining in the claims alleged by the United States to have occurred at the D-J Basin Facilities and additionally citing violations of the Colorado Air Pollution Prevention and Control Act (the "Colorado Act") and its implementing regulations. CDPHE previously issued to Kerr-McGee Rocky Mountain Corporation[1]: (i) a Notice of Violation ("NOV") on or about November 4, 2005 for failure to install pollution control equipment on compressor engines ("RICE" as further defined below) at four of the D-J Basin Facilities; (ii) a Compliance Advisory on or about May 5, 2005 for violations of Operating Permit No. 95OPWE013 and Construction Permit No. 00WE0583 for the Fort Lupton Facility; (iii) a NOV on or about June 15, 2005 for violations of CDPHE Permit No. 02WE0126 Initial Approval, and Modification 1 thereof applicable to the Thermal Oxidizer at the Platteville Station's Amine Unit; (iv) its findings that Kerr-McGee's records for 2005, maintained pursuant to Regulation No. 7, indicated Kerr-McGee's failure to achieve required emission reductions for 9 days between May 1, 2005, and September 30, 2005;

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[1] Kerr-McGee Rocky Mountain Corporation no longer exists, and its former operating facilities in Colorado are now owned by Kerr-McGee Oil and Gas Onshore LP, a wholly-owned subsidiary of Kerr-McGee Corporation.

and (v) the preliminary findings of CDPHE on or about November 10, 2006, based on inspections during the 2006 Ozone Season of Kerr-McGee facilities with condensate storage tanks at which flares were installed to control VOC emissions pursuant to Colorado Air Quality Control Commission Regulation No. 7, Section XII, which findings indicated certain violations;

WHEREAS, Kerr-McGee does not admit the violations occurred and further does not admit any liability for civil penalties, fines, or injunctive relief to the United States or the State arising out of the transactions or occurrences alleged in the Complaint, the Complaint in Intervention, or the NOVs and Compliance Advisory issued by CDPHE;

WHEREAS, Kerr-McGee has worked cooperatively with the Plaintiff and Plaintiff-Intervenor (collectively referred to as Plaintiffs) to settle this matter and committed to reduce or avoid annual emissions in the Uinta Basin and the D-J Basin by an estimated 1,750 tons of nitrogen oxides ("NOx"), 1,156 tons of carbon monoxide ("CO"), 686 tons of sulfur dioxide (SO_2), and 2,195 tons of VOCs, and also to undertake various projects to conserve and return to the market place an estimated 456 million standard cubic feet of natural gas in the first twelve (12) months following full implementation of the Pneumatic Controller (defined herein) retrofits made pursuant to this Consent Decree;

WHEREAS, Kerr-McGee previously developed plans to extensively use electric power for a portion of its natural gas compression needs in the future development of its Uinta Basin operating assets, which if implemented will avoid the emission of significant quantities of air pollutants otherwise produced by natural gas-fired engines used for natural gas compression, and has already implemented "green completion" practices and procedures for completing new wells in both its Uinta Basin and D-J Basin operations to prevent or minimize the flaring and/or venting of natural gas during well completion;

WHEREAS, the United States, the State, and Kerr-McGee (the "Parties") recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated by the Parties in good faith and at arm's length, will avoid litigation among the Parties, and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, the Colorado Act, and their implementing regulations, and that its entry is in the best interests of the Parties and is in the public interest;

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I (Jurisdiction and Venue), and with the consent of the Parties,

IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and the Parties pursuant to 28 U.S.C. §§ 1331, 1345, and 1355, and Sections 113(b), 167, and 304 of the Act, 42 U.S.C. §§ 7413(b), 7477 and 7604. Venue lies in this District pursuant to Sections 113(b) and 304(c) of the Act, 42 U.S.C. §§ 7413(b) and 7604(c), and 28 U.S.C. §§ 1391(b) & (c) and 1395(a), because some of the violations alleged in the Complaint and the Complaint in Intervention are alleged to have occurred in, and Kerr-McGee conducts business in, this judicial district. The Uinta Basin Facilities are located on "Indian country" lands as defined at 18 U.S.C. § 1151 in Uintah County. For purposes of this Consent Decree, or any action to enforce this Consent Decree, Kerr-McGee consents to and will not contest the jurisdiction of the Court over

this matter. For purposes of this Consent Decree, Kerr-McGee agrees that the Complaint and the Complaint in Intervention state claims upon which relief may be granted pursuant to Sections 113, 167, and 304(a) of the Act, 42 U.S.C. §§ 7413, 7477 and 7604(a) and Sections 115, 121, and 122 of the Colorado Act, §§ 25-7-115, 121, and 122 C.R.S.

II. APPLICABILITY

2. The obligations of this Consent Decree apply to and are binding upon the United States and the State, and upon Kerr-McGee, as defined herein, and any of its successors and assigns.

3. Kerr-McGee shall ensure that any of its corporate subsidiaries or affiliates that now or in the future may own or operate any of the Uinta Basin Facilities, the D-J Basin Facilities, or other natural gas production or gathering facilities subject to any work or compliance requirements of this Consent Decree, take all necessary and appropriate actions and provide EPA and/or the State access to facilities, equipment, and information as may be required to enforce this Consent Decree so that Kerr-McGee may fully and timely comply with all requirements of this Consent Decree.

4. In any action to enforce this Consent Decree, Kerr-McGee shall not raise as a defense the failure by any of its officers, directors, employees, agents, contractors, or corporate affiliates or subsidiaries to take any actions necessary to comply with the provisions of this Consent Decree.

III. DEFINITIONS

5. Terms used in this Consent Decree that are defined in the Act or in regulations promulgated pursuant to the Act shall have the meanings assigned to them in the Act or such

regulations, unless otherwise provided in this Decree. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "CDPHE" shall mean the Colorado Department of Public Health and Environment and any of its successor agencies or departments.

b. "Consent Decree" or "Decree" shall mean this Consent Decree and all appendices attached hereto (listed in Section XXX).

c. "Day" shall mean a calendar day unless expressly stated to be a business day. In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday, or federal holiday, the period shall run until the close of business of the next business day.

d. "D-J Basin Facilities" shall collectively mean the Hudson Facility, Dougan Facility, Frederick Facility, Fort Lupton Facility, Brighton Facility, Hambert Facility, and Platteville Facility, all located in the D-J Basin in Weld and Adams Counties, Colorado, as more specifically described in Appendix A. These facilities do not include wellhead facilities.

e. "EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

f. "HAP" shall mean hazardous air pollutant.

g. "Kerr-McGee" shall mean Kerr-McGee Corporation, a Delaware corporation, and the wholly-owned subsidiary of Anadarko Petroleum Corporation as of August 10, 2006, and any of its corporate subsidiaries or affiliates that own or operate any of the Uinta Basin Facilities or the D-J Basin Facilities (each as defined herein), or any other natural gas production or gathering facilities subject to any work or compliance requirements of this Consent Decree, and for which Kerr-McGee Corporation certifies pursuant to Paragraph 112 that it has authority to legally bind such entity to take all actions necessary for Kerr-McGee Corporation to comply with the provisions of this Consent Decree, including but not limited to: Kerr-McGee Oil and Gas Onshore LP, Westport Field Services LLC, Kerr-McGee (Nevada) LLC, and Kerr-McGee Gathering LLC.

h. "Low-Emission Dehydrator" shall be defined as set forth in Paragraph 6 of this Consent Decree.

i. "Paragraph" shall mean a portion of this Decree identified by an Arabic numeral.

j. "Performance Optimization Review" shall mean an evaluation of energy efficiency and the potential for product recovery at certain facilities for purposes of conserving natural gas and returning it to the marketplace.

k. "Plaintiffs" shall mean the United States and the State.

l. "Pneumatic Controller" shall mean a natural gas-driven pneumatic controller.

m. "Potential to Emit" or "PTE" shall mean the maximum capacity of a stationary source to emit a pollutant regulated under the Act under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant regulated under the Act, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable and, as applicable, also legally and practicably enforceable by a state or local air pollution control agency.

n. "Regulation No. 7" shall mean Colorado Air Quality Control Commission ("AQCC") Regulation No. 7, 5 Colo. Code Regs. § 1001-9 (2007).

o. "RICE" shall mean one or more stationary, natural gas-fired reciprocating internal combustion engines.

p. "Section" shall mean a portion of this Decree identified by a Roman numeral.

q. "Title V Permit" shall mean a permit issued pursuant to the federal operating permit program established by Title V of the Act, 42 U.S.C. §§ 7661 - 7661f, and as implemented by 40 C.F.R. Parts 70 (applicable to states) or 71 (applicable to EPA).

r. "TPY" shall mean tons per year.

s. "Uinta Basin Facilities" shall collectively mean the Cottonwood Wash Facility, Ouray Facility, and Bridge Station Facility each located in the

Uinta Basin near Vernal, Utah, as more specifically described in Appendix B.

t. "VOC" shall mean volatile organic compounds as defined in 40 C.F.R. § 51.100(s).

IV. EMISSION REDUCTION REQUIREMENTS

A. LOW-EMISSION DEHYDRATORS

6. "Low-Emission Dehydrator." For purposes of this Consent Decree, a "Low-Emission Dehydrator" shall meet the specifications set forth in Appendix C and shall mean a dehydration unit that:

a. incorporates an integral vapor recovery function such that the dehydrator cannot operate independent of the vapor recovery function;

b. either returns the captured vapors to the inlet of the facility where such dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and

c. has a PTE less than 1.0 TPY of VOCs, inclusive of VOC emissions from the reboiler burner.

<u>Existing Uinta Basin Facilities</u>

7. Kerr-McGee shall continue to operate and maintain Low-Emission Dehydrators for all gas dehydration performed at its existing Uinta Basin Facilities.

8. By no later than 30 Days after the date of lodging of this Consent Decree, Kerr-McGee shall provide a written notice to EPA and certify that each Low-Emission Dehydrator

installed at Kerr-McGee's existing Uinta Basin Facilities meets the criteria set forth in Paragraph 6.

New Facilities in the Uinta Basin

9. Beginning as of the date of lodging of this Consent Decree, and continuing for so long as this Consent Decree is in effect, Kerr-McGee shall install and operate Low-Emission Dehydrators at all compressor stations or other facilities utilizing equipment to dehydrate natural gas in the Uinta Basin.

10. Kerr-McGee shall provide written notice to EPA within 60 Days of each installation under Paragraph 9, and include a description of the equipment installed and a certification pursuant to Paragraph 112 that the Low-Emission Dehydrator meets the criteria set forth in Paragraph 6.

11. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV.A., and shall report the status of its compliance with these requirements in its Annual Reports submitted pursuant to Section XII (Reporting Requirements).

B. CONDENSATE STORAGE TANKS

Cottonwood Wash and Ouray Facilities in the Uinta Basin

12. Within 180 Days after the date of lodging of this Consent Decree, Kerr-McGee shall install and operate enclosed flares at the Cottonwood Wash Facility and Ouray Facility or install a non-flare alternative pursuant to Paragraph 18 to meet a 95% or greater reduction of VOC emissions from all condensate storage tanks located at each facility.

13. Kerr-McGee shall design, install, and operate each enclosed flare required pursuant to this Section IV.B. in accordance with the requirements of 40 C.F.R. § 60.18(c)-(e) and the manufacturer's written instructions or procedures necessary to achieve the emission reductions listed in Paragraph 12. Kerr-McGee shall submit to EPA a worksheet setting forth the design calculations for each proposed enclosed flare, including heat content determination, exit velocity determination, and flow rate estimates, within 60 Days after the lodging this Consent Decree.

14. Upon startup of each enclosed flare, Kerr-McGee shall operate and maintain an auto-ignition device equipped with a thermocouple that reignites the pilot flame whenever it goes out.

15. No later than 60 Days following the start-up of each enclosed flare, Kerr-McGee shall submit a certification pursuant to Paragraph 112 to EPA that Kerr-McGee has complied with the requirements of Paragraphs 12 through 14.

16. Kerr-McGee shall inspect each enclosed flare weekly and document whether the pilot light on each enclosed flare was lit or the enclosed flare was bypassed at the time of the inspection.

17. Kerr-McGee shall notify EPA of all instances that a pilot light on each enclosed flare was not lit or the enclosed flare was bypassed, and the duration of each incident, with each Annual Report submitted pursuant to Section XII (Reporting Requirements).

18. Instead of designing, operating, maintaining, and monitoring an enclosed flare in accordance with the applicable requirements of this Section IV.B., or as a future replacement of, or preferred primary means of emission control over, an enclosed flare installed to comply with

this Section IV.B., Kerr-McGee may elect to control emissions from condensate storage tanks at these facilities by installing and operating a vapor recovery unit ("VRU"), system for cascading stabilization of condensate, or any other system to capture and beneficially use or prevent VOC emissions from condensate tanks. No later than 30 Days prior to installation, Kerr-McGee shall submit to EPA a monitoring plan to ensure the non-flare alternative meets a 95% or greater reduction in VOC emissions.

19. By no later than 60 Days after the start-up of any such enclosed flare and/or non-flare alternative, Kerr-McGee shall, where applicable, obtain all necessary federally-enforceable, non-Title V permits and amend its Title V Permit applications for the Cottonwood Wash and Ouray Facilities, as appropriate, to incorporate all enclosed flare and/or non-flare alternative installation, operation, monitoring and reporting requirements as set forth in this Section IV.B.

Brighton Facility in the D-J Basin

20. By no later than June 30, 2007, Kerr-McGee shall install and operate an enclosed flare at the Brighton Facility to meet a 95% destruction efficiency for VOC emissions from all condensate storage tanks located at the Brighton Facility.

21. Kerr-McGee shall design, install and operate the enclosed flare in accordance with the requirements of "Regulation No. 7", and the manufacturer's written instructions or procedures necessary to achieve the emission reductions listed in Paragraph 20.

22. By no later than June 1, 2007, Kerr-McGee shall have submitted a worksheet to CDPHE setting forth its design calculations for the proposed enclosed flare, including heat content determination, exit velocity determination, and flow rate estimates.

23. Upon startup of the enclosed flare, Kerr-McGee shall operate and maintain an auto-ignition device equipped with a thermocouple that reignites the pilot flame whenever it goes out.

24. By no later than 60 Days following start-up of the enclosed flare, Kerr-McGee shall submit a certification pursuant to Paragraph 112 to CDPHE that it has complied with the requirements of Paragraphs 20-23.

25. Kerr-McGee shall inspect the enclosed flare and document whether the pilot light on the enclosed flare was lit or the enclosed flare was bypassed at the time of the inspection, as required by Regulation No. 7.

26. Kerr-McGee shall notify CDPHE of all instances that a pilot light on the enclosed flare was not lit or the enclosed flare was bypassed, and the duration of each incident, with each Annual Report submitted pursuant to Section XII (Reporting Requirements), and any other reports required to be submitted to CDPHE under Regulation No. 7.

27. By no later than 60 Days after the start-up of such enclosed flare, Kerr-McGee shall apply to CDPHE for a construction permit and to amend its Title V Permit, as appropriate, to incorporate all enclosed flare installation, operation, monitoring and reporting requirements as set forth in this Section IV.B., or to request that CDPHE rescind its Title V Permit, as appropriate.

28. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV.B., and shall report the status of its compliance with these requirements in its Annual Reports submitted pursuant to Section XII (Reporting Requirements).

C. COMPRESSOR ENGINES IN THE D-J BASIN

29. Kerr-McGee shall install, operate and maintain emission control equipment to reduce: (i) NO_x, CO and VOC emissions from seven existing two-stroke, lean-burn ("2SLB") RICE located at the Frederick, Dougan, and Hudson Facilities; and (ii) CO and VOC emissions from four existing 2SLB RICE located at the Fort Lupton Facility, in accordance with the control requirements of this Section IV.C. Alternatively, Kerr-McGee may permanently remove from service any of these existing eleven 2SLB RICE located at the Frederick, Dougan, Hudson or Fort Lupton Facilities either before or after meeting the additional control requirements of this Section IV.C., and it may also replace one or more such existing 2SLB RICE with new RICE subject to all applicable permitting requirements then in effect, in accordance with the schedule in Paragraphs 30 and 31. Any such new RICE shall meet the requirements of Regulation No. 7, § XVII regardless of whether such new RICE is relocated from a site within the State. Such new RICE shall have a manufacture date no earlier than January 1, 2004.

30. The emission control equipment for the seven 2SLB RICE located at the Frederick, Dougan, and Hudson Facilities shall consist of: (i) new or remanufactured turbochargers; (ii) pre-combustion chambers; (iii) after-coolers with auxiliary water cooling, as needed; (iv) high-pressure fuel injection; and (v) oxidation catalysts. All such equipment shall be installed and operational, or one or more of the 2SLB RICE shall be replaced, in accordance with the following schedule:

a. One Clark TLAD engine at the Hudson Facility - no later than January 4, 2008;

b. A second Clark TLAD engine at the Hudson Facility - no later than February 22, 2008;

c. A third Clark TLAD engine at the Hudson Facility - no later than April 11, 2008;

d. The fourth and last Clark TLAD engine at the Hudson Facility - no later than May 30, 2008;

e. One Cooper-Quad engine at the Frederick Facility - no later than November 14, 2008 or certify by November 14, 2008 pursuant to Paragraph 112 that one Cooper-Quad RICE, specifically identified by AIRS Identification Number and serial number, will be replaced no later than January 16, 2009;

f. The second and last Cooper-Quad engine at the Frederick Facility - no later than January 16, 2009 or replace the Cooper-Quad RICE, specifically identified by AIRS Identification Number and serial number, no later than January 16, 2009; and

g. Dougan Engine 21 (a Cooper-Quad) - no later than March 20, 2009 or replace the Cooper-Quad RICE no later than March 20, 2009.

31. The emission control equipment for the 2SLB RICE at the Fort Lupton Facility shall consist of oxidation catalysts. The oxidation catalysts shall be installed and operational, or the 2SLB RICE shall be replaced, in accordance with the following schedule:

a. One Fairbanks-Morse MEP engine at the Fort Lupton Facility - no later than January 4, 2008 or certify by January 4, 2008 pursuant to Paragraph

112 that one Fairbanks-Morse MEP RICE, specifically identified by AIRS Identification Number and serial number, will be replaced no later than May 30, 2008;

b. A second Fairbanks-Morse MEP engine at the Fort Lupton Facility - no later than February 22, 2008 or certify by February 22, 2008 pursuant to Paragraph 112 that one Fairbanks-Morse MEP RICE, specifically identified by AIRS Identification Number and serial number, will be replaced no later than May 30, 2008;

c. A third Fairbanks-Morse MEP engine at the Fort Lupton Facility - no later than April 11, 2008 or certify by April 11, 2008 pursuant to Paragraph 112 that one Fairbanks-Morse MEP RICE, specifically identified by AIRS Identification Number and serial number, will be replaced no later than May 30, 2008; and

d. The fourth and last Fairbanks-Morse MEP engine at the Fort Lupton Facility - no later than May 30, 2008 or replace the Fairbanks-Morse MEP RICE, specifically identified by AIRS Identification Number and serial number no later than May 30, 2008.

32. The emission control equipment for each existing 2SLB RICE at the Frederick, Dougan and Hudson Facilities shall meet the following control requirement for NOx: 2.0 grams/hp-hr., or an equivalent lbs./MMBTU limit, when the RICE is operating at a 90% load or higher.

33. The emission control equipment for each existing 2SLB RICE shall have a control requirement of 58% destruction efficiency for CO when the RICE is operating at a 90% load or higher.

34. All emission control equipment shall be appropriately sized for each existing 2SLB RICE. Immediately following installation of each emission control device, Kerr-McGee shall operate and maintain each existing 2SLB RICE and associated emission control and related equipment according to all manufacturer's written instructions or procedures necessary to achieve the emission reductions listed in Paragraphs 32 and/or 33. Oxidation catalysts shall be operated in accordance with Regulation No. 7, Section XVI.

35. Kerr-McGee shall conduct an initial emission test on each existing 2SLB RICE to demonstrate compliance with the control requirements of Paragraphs 32 and/or 33 pursuant to the Test Protocols set forth in Appendix D. Such initial emission tests shall be conducted no later than 60 Days after installation of the emission control equipment and startup of each existing 2SLB RICE.

36. If any emission control equipment fails to meet the control requirements of Paragraphs 32 and/or 33, Kerr-McGee shall take appropriate steps to correct such non-compliance and retest the emission control equipment no later than 30 Days after the initial emission test. Kerr-McGee shall submit a report to CDPHE no later than 30 Days after each such retest. The retest report will include a summary of the steps taken to comply with the control requirements of Paragraphs 32 and/or 33, and the retest results.

37. Upon successful demonstration that the emission control equipment has met the control requirements of Paragraphs 32 and/or 33, Kerr-McGee shall thereafter operate and

maintain the emission control equipment to meet those requirements in accordance with the Operation and Maintenance Plan ("O&M Plan") Kerr-McGee submits for approval to CDPHE. Kerr-McGee shall submit a proposed O&M Plan to CDPHE no later than 60 Days after a successful test or retest.

38. Kerr-McGee shall apply to CDPHE for a construction permit and amend its existing Title V Permit for each facility to incorporate the use of the emission control equipment required by this Section IV.C., as well as the applicable performance, monitoring and reporting requirements. Kerr-McGee shall submit such applications for each facility no later than 60 Days after the date of the last compliance demonstration for the last affected 2SLB RICE at each such facility.

39. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV.C., and any applicable regulatory requirements, and shall report the status of its compliance with these requirements in its Annual Reports, submitted pursuant to Section XII (Reporting Requirements).

D. COMPRESSOR ENGINES IN THE UINTA BASIN

Existing RICE in the Uinta Basin

40. By no later than December 15, 2007, Kerr-McGee shall install and operate oxidation catalysts on each RICE operating in the Uinta Basin with a nameplate rating of 500 horsepower ("hp") or greater listed in Appendix E (all of which Kerr-McGee represents are located at HAP minor sources).

41. The oxidation catalysts installed on each RICE listed in Appendix E shall achieve a 93% destruction efficiency for CO when each RICE is operating at a 90% load or higher.

42. Immediately following installation of each oxidation catalyst, Kerr-McGee shall operate and maintain each RICE and oxidation catalyst according to the catalyst manufacturer's written instructions or procedures necessary to achieve the emission reductions listed in Paragraph 41.

43. Kerr-McGee shall conduct an initial emissions test of each oxidation catalyst to demonstrate compliance with the CO destruction efficiency specified in Paragraph 41 using a portable analyzer in accordance with the Test Protocol set forth in Appendix F. An initial emissions test on each oxidation catalyst installed pursuant to the requirements of Paragraph 40 shall be completed no later than 60 Days after the last oxidation catalyst installation on the RICE listed in Appendix E.

44. If any oxidation catalyst fails to meet the destruction efficiency specified in Paragraph 41, Kerr-McGee shall take appropriate steps to correct such non-compliance and retest the oxidation catalysts within 30 Days after the initial test(s). Kerr-McGee shall submit a report to EPA no later than 30 Days after each retest. The retest report will include a summary of the steps taken to comply with the control requirement in Paragraph 41 and the retest results.

45. Upon successful demonstration that an oxidation catalyst has met the destruction efficiency as specified in Paragraph 41, Kerr-McGee shall thereafter test the oxidation catalyst emission control efficiency on a semi-annual calendar-year basis using a portable analyzer in accordance with the Test Protocol set forth in Appendix F.

46. Kerr-McGee shall report to EPA in writing concerning all activities completed pursuant to the preceding Paragraphs 40 through 45. Such report shall be submitted no later than 60 Days after the initial test deadline contained in Paragraph 43. The report shall contain the following information applicable to each RICE:

a. RICE make, model, nameplate hp rating, location, installation date (when available) and manufacturer emission data;

b. catalyst make, model, installation date and manufacturer emission data;

c. initial emission test results including dates and times of test runs, names of employee(s) or contractor(s) who conducted the test, and oxygen (O_2) and CO concentration results at the inlet and outlet of the oxidation catalyst for each run; the percent reduction of CO achieved for each test run after normalizing CO concentration to a dry basis and to 15% oxygen; length of run times, and average percent engine load during each run;

d. a catalyst maintenance log (e.g., date of last catalyst replacement, number of engine operating hours since last catalyst replacement, and date and description of any catalyst maintenance activities); and

e. a certification pursuant to Paragraph 112 of the information contained in the report in accordance with Section XII (Reporting Requirements).

47. All subsequent semi-annual test results shall be included in Annual Reports to be submitted by Kerr-McGee regarding the RICE listed in Appendix E, as required by Section XII (Reporting Requirements), and shall include the information set forth in the preceding Paragraph 46.

48. If otherwise required by applicable regulations implementing the Act, Kerr-McGee shall apply for a permit for any RICE in Appendix E prior to termination of the Consent Decree.

New RICE in the Uinta Basin at HAP Minor Sources

49. Beginning on the date of the lodging of this Consent Decree, and continuing for so long as this Consent Decree is in effect, any new RICE with a nameplate rating of 500 hp or greater installed by Kerr-McGee at any facility in the Uinta Basin shall be lean-burn or achieve comparable emission reductions, and be equipped with catalyst controls.

50. For those RICE installed by Kerr-McGee in the Uinta Basin, the oxidation catalysts that are required to be installed pursuant Paragraph 49 shall achieve a 93% destruction efficiency for CO when each RICE is operating at a 90% load or higher.

51. By no later than 60 Days following the installation of a catalyst on any new RICE pursuant to Paragraph 49, Kerr-McGee shall conduct an initial emissions test of such catalyst to demonstrate compliance with the destruction efficiency specified in Paragraph 50, using a portable analyzer in accordance with the Test Protocol set forth in Appendix F.

52. If the catalyst fails to meet the destruction efficiency as specified in Paragraph 50, Kerr-McGee shall take appropriate steps to correct such non-compliance and retest the oxidation catalyst within 30 Days after the initial test. Kerr-McGee shall submit a report to EPA no later than 30 Days after each retest. The retest report shall include a summary of the steps taken to comply and the retest results.

53. Upon successful demonstration that the catalyst has met the destruction efficiency specified in Paragraph 50, Kerr-McGee shall thereafter test the oxidation catalyst emission

control efficiency on a semi-annual calendar-year basis using a portable analyzer in accordance with the Test Protocol set forth in Appendix F.

54. Kerr-McGee shall submit a report to EPA within 60 Days after each initial test is performed pursuant to Paragraph 51. The report shall contain the initial test results and the following information applicable to each RICE:

a. RICE make, model, nameplate hp rating, location, installation date and manufacturer emission data;

b. catalyst make, model, installation date and manufacturer emission data;

c. initial emission test results including date and times of test runs, name(s) of employee(s) or contractor(s) who conducted the test, and O_2 and CO concentration results at the inlet and outlet of the oxidation catalyst for each run; the percent reduction of CO achieved for each test run after normalizing CO concentration to a dry basis and to 15% oxygen; length of run times, and percent engine load at each run;

d. a certification pursuant to Paragraph 112 of the information contained in the report in accordance with Section XII (Reporting Requirements).

55. Kerr-McGee shall include all subsequent semi-annual results in the Annual Report submitted pursuant to Section XII (Reporting Requirements), as well as the information gathered pursuant to the preceding Paragraph 54, and a catalyst maintenance log (e.g., date of last catalyst replacement, number of engine operating hours since last catalyst replacement, and date and description of any catalyst activities).

56. If otherwise required by applicable regulations implementing the Act, Kerr-McGee shall apply for a permit for any new RICE subject to this Section IV.D. prior to termination of the Consent Decree.

57. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV. D., and shall report the status of its compliance with these requirements in its Annual Reports submitted pursuant to Section XII (Reporting Requirements).

E. **PNEUMATIC CONTROLLERS**

Existing High-Bleed Pneumatic Controllers

58. Retrofits: Kerr-McGee shall retrofit all "high-bleed" Pneumatic Controllers listed in Appendices G and H, with "low-bleed" Pneumatic Controllers, in accordance with the requirements of this Section IV.E. For purposes of this Consent Decree, a "high-bleed" Pneumatic Controller is any Pneumatic Controller that has the capacity to bleed in excess of six standard cubic feet of natural gas per hour (50,000 scf/year) in normal operation. During the performance of such work Kerr-McGee shall, to the extent practicable, repair or replace leaking gaskets, tubing fittings and seals, and all work will be completed so as to minimize potential emissions associated with the retrofitting project.

59. By no later than September 30, 2007, Kerr-McGee shall install retrofit "low-bleed" Pneumatic Controllers on at least one-half of the high-bleed Pneumatic Controllers listed in Appendix G, and on at least one-half of the high-bleed Pneumatic Controllers listed in Appendix H.

60. Kerr-McGee shall install retrofit "low-bleed" Pneumatic Controllers on the remainder of the high-bleed Pneumatic Controllers listed in Appendices G and H by no later than May 31, 2008.

61. Replacements: By no later than two years after the date of lodging of this Consent Decree, Kerr-McGee shall replace no less than 370 additional high-bleed Pneumatic Controllers that were not amenable to retrofit with low or no-bleed Pneumatic Controllers in the Wattenberg Gas Gathering System, and as many more such high-bleed Pneumatic Controllers as may be replaced at a total cost of $500,000 (inclusive of both capital and installation costs).

62. Within 60 Days after the retrofit of Pneumatic Controllers listed in Appendices G and H is completed, and within 60 Days after the replacement of Pneumatic Controllers required by Paragraph 61, Kerr-McGee shall provide EPA, and as applicable CDPHE, a report that certifies the completion of each such project and an accompanying spreadsheet that identifies each unit retrofitted or replaced, its site location, its service, the date the retrofit or replacement was completed, the estimated bleed rate reductions and corresponding estimates of both annual VOC reductions (on a calendar-year basis) and the amount of natural gas conserved, and the approximate cost of each retrofit and replacement.

New Construction

63. Beginning on the date of the lodging of this Consent Decree, and continuing through January 1, 2017, Kerr-McGee shall install and operate low or no-bleed Pneumatic Controllers to conserve natural gas at all newly constructed facilities in the Uinta Basin and D-J Basin, where instrument air is not otherwise available. Kerr-McGee need not, however, install

low or no-bleed controllers at sites for which Kerr-McGee can demonstrate that the use of low or no-bleed pneumatic devices would not be technically or operationally feasible.

64. Kerr-McGee shall have implemented the mandatory management directive (Appendix I) which requires the use of low-bleed Pneumatic Controllers at all newly constructed facilities in the D-J and Uinta Basins.

65. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV. E., and shall report the status of its compliance with these requirements, in its Annual Reports submitted pursuant to Section XII (Reporting Requirements).

F. SULFUR REMOVAL TECHNOLOGY IN THE UINTA BASIN

66. Beginning on the date of lodging of this Consent Decree and continuing for so long as this Consent Decree is in effect, Kerr-McGee shall install and operate solid-bed or liquid-bed sulfur removal processes when necessary to remove hydrogen sulfide ("H_2S") from natural gas in the Uinta Basin, in lieu of amine-based sulfur removal with flaring of removed H_2S.

67. Kerr-McGee shall provide written notice to EPA no later than 60 Days following each installation and startup of a liquid-bed sulfur removal unit under Paragraph 66. Such notice shall include a description and the location of all liquid-bed sulfur removal equipment installed, an estimate of the annual amount of SO_2 emissions to be avoided (on a calendar-year basis), and a summary spreadsheet showing service conditions and actual capital costs.

68. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section IV. F.,

and shall report the status of its compliance with these requirements in its Annual Reports submitted pursuant to Section XII (Reporting Requirements).

V. ADMINISTRATIVE REQUIREMENTS

A. PLATTEVILLE FACILITY

69. Within 30 Days after the date of lodging of this Consent Decree, Kerr-McGee shall submit for CDPHE's approval and incorporation as a requirement of Colorado Construction Permit No. 02WE0126 an operation and maintenance ("O&M") plan for the reboiler that controls VOC emissions from the amine gas treatment system at the Platteville Facility.

70. Kerr-McGee's O&M plan shall:

a. Provide a routine program to minimize soot build-up of the reboiler burner;

b. Incorporate the burner manufacturer's written instructions or procedures necessary to ensure proper combustion; and

c. Conform to applicable requirements of CDPHE's AQCC Common Provisions Regulation, AQCC's Regulation Nos. 1, 2, 3, and 6, and 40 C.F.R. Part 60, Subparts A and Dc.

71. CDPHE shall either approve Kerr-McGee's plan or provide written comments and requested changes within 30 Days of submission of the plan. Kerr-McGee shall have an additional 30 Days from receipt of CDPHE's written response to either amend the plan and resubmit it to CDPHE, or to begin implementation of O&M in accordance with the approved plan. Upon CDPHE's approval, the O&M plan shall become an enforceable requirement of Colorado Construction Permit No. 02WE0126.

B. FORT LUPTON FACILITY

72. Within 30 Days after the date of lodging of this Consent Decree, Kerr-McGee shall propose to CDPHE a consolidated annual allowable VOC emission limit for equipment leaks from components at the Fort Lupton Facility that are in VOC hydrocarbon service as described at 40 C.F.R. § 60.632(f). The following sources of VOC emissions shall be subject to such consolidated emission limit:

   a. Equipment leaks from those components of the Fort Lupton Facility subject to Condition 6.1 of CDPHE Operating Permit No. 95OPWE013 (30.8 TPY); and

   b. Equipment leaks from components of the natural gas liquids ("NGL") extraction unit subject to Condition 2 of CDPHE Construction Permit No. 00WE0583 (46.4 TPY).

73. Kerr-McGee's proposal to CDPHE shall be made as an application to amend the Title V Permit for the Fort Lupton facility. The Parties agree that incorporation of this requirement into the Title V Permit for the Fort Lupton facility may be made by "administrative amendment" under 40 C.F.R. § 70.7(d) and corresponding State Title V rules, where allowed by State law. CDPHE shall administer Kerr-McGee's application as a routine application for a Title V permit amendment. Until such time as CDPHE has taken final agency action with regard to such application, Kerr-McGee shall comply with the following interim emission limit for the Fort Lupton Facility, consistent with applicable EPA guidance on appropriate emission factors and control percentages for components in hydrocarbon service at facilities with quarterly leak detection and repair ("LDAR") programs in place: 77.2 TPY of VOCs during any 12-month

period (on a rolling basis) from equipment leaks at the Fort Lupton Facility subject to the requirements of 40 C.F.R. Part 60, Subpart KKK and Regulation No. 7. For the purpose of demonstrating compliance with this interim emission limit, emissions shall be calculated in accordance with the methodology contained in Appendix J.

VI. LIMITS ON POTENTIAL TO EMIT

74. The control requirements established in Sections IV.A. (Low-Emission Dehydrators), IV.B. (Condensate Storage Tanks), IV.C. (Compressor Engines in the D-J Basin), IV.D. (Compressor Engines in the Uinta Basin) and IV.E. (Pneumatic Controllers), under this Consent Decree shall be considered "federally enforceable" and, as applicable, "legally and practicably enforceable" for purposes of calculating the PTE of a source or facility as may be applicable under the Act and the Colorado Act and any implementing federal or Colorado regulations.

75. The PTE for VOCs from Low-Emission Dehydrators installed and certified pursuant to this Consent Decree at any facility in the Uinta or D-J Basins shall be limited by the control requirements set forth in Section IV.A. (Low-Emission Dehydrators), and shall be federally enforceable on that basis.

76. The PTE for VOC emissions from condensate storage tanks at the Cottonwood Wash Facility and Ouray Facility shall be limited by the requirement that such emissions will be controlled by a flare, VRU, or other non-flare alternatives pursuant to the criteria set forth in Section IV.B. (Condensate Storage Tanks) and shall be federally enforceable on that basis.

77. The PTE for CO and formaldehyde for all RICE in the Uinta Basin with a nameplate rating of 500 hp or greater shall be limited by the requirement that emissions be

controlled by catalysts which meet a destruction efficiency for CO set forth in Paragraphs 41 and 50 and shall be federally enforceable on that basis.

78. The PTE for CO for the eleven 2SLB RICE in the D-J Basin shall be limited by the requirements of Section IV.C. (Compressor Engines in the D-J Basin) that such emissions will be controlled by oxidation catalysts which meet the control requirements set forth in Paragraph 33 and shall be federally enforceable on that basis.

79. The PTE for NOx for the 2SLB RICE at the Frederick, Dougan and Hudson Facilities shall be limited by the requirement that equipment be upgraded for purposes of reducing emissions which meet the control requirements set forth in Paragraph 32 and shall be federally enforceable on that basis.

VII. AMBIENT AIR MONITORING

80. By no later than six months after entry of this Consent Decree, Kerr-McGee shall fund the purchase, installation and initial operation of ambient air quality and meteorological monitoring station(s) in and/or adjacent to the Uinta Basin, subject to a $300,000 cap on Kerr-McGee's total expenditures to comply with this Section VII. The ambient air quality monitor(s) shall be designed to monitor ozone, NOx and $PM_{2.5}$ concentrations. The meteorological station(s) shall have a 10 meter tower and be designed to monitor wind speed, wind direction, temperature and solar radiation. The station(s) shall be designed to gather multilevel meteorological data necessary for use in air quality monitoring under current federal and state laws and regulations.

81. Kerr-McGee shall work cooperatively with EPA, the Utah Department of Environmental Quality (UDEQ) and the Ute Indian Tribe of the Uintah and Ouray Reservation

(the "Northern Ute Tribe") regarding the location of monitor(s), schedule for project implementation and coordination of their initial operation. The station(s) shall meet the siting, methodology and operational requirements of 40 C.F.R. Part 58, and shall be sited in a representative location upwind of the Uinta Basin and/or a representative central location within the Uinta Basin. Additional guidance for meteorological monitoring is contained in "Quality Assurance Handbook for Air Pollution Measurement Systems, " Vol. IV, "Meteorological Measurements." Actual monitoring site selection shall be subject to approval by EPA and Kerr-McGee, after review and comment on proposed locations by the UDEQ and the Northern Ute Tribe. All monitoring data shall be collected in a manner reasonably calculated to meet EPA's quality assurance/quality control ("QA/QC") requirements of 40 C.F.R. Part 58, App. A. Additional guidance is provided in "Quality Assurance Handbook for Air Pollution Measurement Systems."

82. Subject to a $300,000 cost cap, Kerr-McGee shall fund the operation and maintenance of up to two (2) stations, and the collection and distribution of monitoring data for the station(s) until Kerr-McGee has expended $300,000 in capital, installation, operation and maintenance costs. Kerr-McGee shall certify in accordance with Paragraph 112 that it has expended $300,000 in capital, installation, operation and maintenance costs for up to two (2) stations.

VIII. MULTI-PHASE PIPING/TANKLESS WELL-SITE PILOT PROJECT

83. Kerr-McGee shall complete a study of the technical and operational feasibility of using a system to gather multi-phase fluids (liquid and gas constituents) from multiple producing natural gas well-sites for collection, separation and metering at a central facility in the Uinta

Basin ("Feasibility Study"), and if technically and operationally feasible, shall implement a pilot project to demonstrate such technology in the Uinta Basin ("Multi-Phase Pilot"), in accordance with the requirements of this Section VIII. The Feasibility Study and Multi-Phase Pilot shall focus on a proposed system to: (i) eliminate the storage of hydrocarbon liquids and produced water at individual wellhead facilities within the system; and (ii) reduce emissions of VOCs from condensate storage tanks to be located at a central collection point. Subject to the cost cap set forth in Paragraph 86, the Multi-Phase Pilot shall include: (i) at least sixteen new or existing well pads and multi-phase piping from those well pads to a central collection point; and (ii) separation, liquid storage, gas metering equipment, and VOC emission control or capture, to the extent emissions are not otherwise prevented through process changes.

84. Feasibility Study: Kerr-McGee shall complete the Feasibility Study in accordance with the scope of work ("FS SOW") attached as Appendix K. No later than 90 Days after the date of lodging this Consent Decree, Kerr-McGee shall submit a written report of the conclusions of the Feasibility Study to EPA for review and concurrence. In the event the Feasibility Study concludes that the Multi-Phase Pilot is not technically or operationally feasible to implement, Kerr-McGee shall have no further obligations under this Section VIII.

85. Multi-Phase Pilot: If the Multi-Phase Pilot is found to be technically and operationally feasible in the Feasibility Study, Kerr-McGee shall submit to EPA for review and approval a proposed scope of work ("Multi-Phase Pilot SOW") to implement the Multi-Phase Pilot in a manner consistent with the conclusions of the Feasibility Study. The Multi-Phase Pilot SOW shall include an estimate of "Added Incremental Costs," which for purposes of this Section VIII, are defined as the total costs over and above the costs of conventional well-site

development, accounting for normal construction. EPA shall either approve the Multi-Phase Pilot SOW or provide written comments on requested changes within 30 Days of receipt of such Multi-Phase Pilot SOW. Kerr-McGee shall have an additional 30 Days from receipt of EPA's written response to either amend the Multi-Phase Pilot SOW and resubmit it to EPA, or to invoke the dispute resolution procedures set forth in Section XV (Dispute Resolution), and EPA shall have an additional 30 Days from resubmission to comment upon or approve such revised Multi-Phase Pilot SOW.

86. In the event that Kerr-McGee can document to EPA's satisfaction, in accordance with Paragraph 85, that the Added Incremental Costs of the Multi-Phase Pilot to be implemented pursuant to the EPA-approved Multi-Phase Pilot SOW will exceed $750,000, Kerr-McGee shall implement the Multi-Phase Pilot at as many well pads as can be funded for $750,000 in Added Incremental Costs. In the event that EPA and Kerr-McGee disagree on the total Added Incremental Costs, Kerr-McGee shall bear the burden of demonstrating by a preponderance of evidence that such costs exceed the $750,000 cost cap.

87. Kerr-McGee shall provide EPA with semi-annual, calendar-year progress reports, beginning 180 Days following EPA's approval of the Multi-Phase Pilot SOW, documenting progress on the Multi-Phase Pilot. The progress report shall include a description of the schedule status for engineering, procurement, construction and start up of the Multi-Phase Pilot, and an updated estimate of "Added Incremental Costs."

88. By no later than 18 months following EPA's approval of the Multi-Phase Pilot SOW, Kerr-McGee shall have installed and begun operation of the Multi-Phase Pilot in accordance with the approved Multi-Phase Pilot SOW.

89. Within 90 Days of the installation and startup of the Multi-Phase Pilot, Kerr-McGee shall provide EPA a final report that includes the following information:

a. A description of the project as completed, including: (i) a topographic area map showing the well pads, multi-phase pipelines, and central liquids gathering; (ii) a process description with a summary of gas, condensate and water production rates since project startup; (iii) process flow diagrams for a typical well pad and for central liquids gathering equipment; (iv) a representative condensate liquids sample analysis from a well pad and from the outlet of central liquid separation; and (v) the API gravity and RVP for such required condensate samples;

b. A discussion of the operating challenges presented by the Multi-Phase Pilot and their means of resolution;

c. An itemization of the Added Incremental Costs of the project as completed;

d. An itemized estimate of both incremental added and saved operating costs compared to conventional gas gathering methods; and

e. A description of air quality and other environmental benefits attributable to the project, together with any calculations and process simulations used to estimate air emission reductions and natural gas conserved.

90. General Record-Keeping Requirement: Kerr-McGee shall maintain records and information adequate to demonstrate its compliance with the requirements of this Section VIII, and any applicable regulatory requirements, and shall report the status of its compliance with

these requirements in its Annual Reports until the Multi-Phase Pilot is fully implemented and operating, as set forth in Section XII (Reporting Requirements).

IX. PERFORMANCE OPTIMIZATION REVIEW

91. Within one year after the date of lodging of this Consent Decree, Kerr-McGee shall complete a Performance Optimization Review ("POR") to increase energy efficiency and enhance product recovery at five facilities in the Uinta Basin and five facilities in the D-J Basin in accordance with the Scope of Work attached as Appendix L. The five facilities in the Uinta Basin shall consist of four well-site facilities (two shall be at least five years old, one shall be less than five years old, and one shall be a new drill) and one (1) compressor station. The five facilities in the D-J Basin will consist of four well-site facilities (two shall be at least ten years old, one shall be less than ten years old, and one shall be a new drill) and the Platteville Facility.

92. Kerr-McGee's POR shall be performed by third-party consultants acceptable to EPA and CDPHE. Performance of the POR may be temporarily suspended during entry pursuant to Paragraph 140.

93. The scope of the POR is expressly limited to the following activities, as set forth in the POR SOW:

a. Pressure Relief Devices - repair or replace components, as appropriate, to specifically reduce product losses;

b. Pneumatic Controllers - evaluate for use of low-bleed devices or instrument air;

c. Production Separators - identify optimal pressures and temperatures, and reset as needed;

d. Dehydrators - evaluate for use of condensers, flares, flash tanks and electric pumps to reduce product losses;

e. Internal Combustion Engines - evaluate maintenance practices and planned shutdown procedures to minimize product losses from blow down and the use of starter gas;

f. Flare and Vent Systems - evaluate flare and vent system components and associated operating procedures to reduce the loss of product, where possible;

g. Producing Wells - install plunger lifts and perform "green completion" practices on new wells, as appropriate;

h. Operating Pressures - review and optimize, where possible; and

i. Component Inspections and Repairs - perform component inspections using OVA, TVA, or other CDPHE-approved leak detection field equipment and repair or replace leaking components, as appropriate, to enhance product recovery.

94. POR Reports. Within 60 Days of completion of the POR, Kerr-McGee shall submit a POR Report to EPA for the Uinta Basin and a POR Report to CDPHE for the D-J Basin which shall include:

a. the contractor(s) used to conduct the POR;

b. the name, location and original construction date of each of the well-site facilities and the compressor station at which the POR was completed;

c. a general description of the components by type and service that were inspected, how they were inspected, a summary and description of any repairs made, an estimate of natural gas conserved as a result of the repairs to the extent quantifiable, and the repair cost;

d. a general description of the pressure relief devices that were inspected, how they were inspected, a summary description of any repairs made, an estimate of natural gas conserved as a result of the repairs to the extent quantifiable, and the repair cost;

e. an evaluation of pneumatic devices for use of low-bleed devices or instrument air, and potential product losses avoided;

f. a description of the review of production separators, identification of those for which optimal pressures and temperatures were calculated and how that was done; a comparison of those values to prior separator operating conditions, a summary of the adjustments to pressures or temperatures that were made, an estimate of the amount of natural gas conserved as a result, and the cost if significant, to adjust pressures and temperatures;

g. a description of the evaluation of dehydrators for the use of condensers, flares, flash tanks, and electric pumps; a summary of the projects identified as a result of such review for possible future implementation by Kerr-McGee on a voluntary basis; if sufficient data exists to prepare an estimate, an estimate of the amount of natural gas potentially conserved if such projects were implemented, and the cost to implement such projects;

h. a description of the review of RICE shutdown procedures to reduce blow down and the use of starter gas; a summary of any changes that were made based on such review; an estimate of product losses avoided as a result of any changes made, if reasonably capable of estimation; and the cost to implement such changes;

i. a description of the review of flare and vent systems, a summary of the repairs made, if any; an estimate of the amount of natural gas conserved as a result of repairs made, and the cost to implement such repairs;

j. a list of well names and locations at which plunger lift systems were installed, if any, or at which green completion procedures were followed; a description of any plunger lift system(s) used and the well condition(s) that made such system(s) practicable or how new well completion procedures were "green"; an estimate of the amount of natural gas conserved as a result of POR evaluations of certain producing wells, and the cost to implement any such systems and/or procedures; and

k. a description of how operating pressures were evaluated and, where possible, optimized; an estimate of the amount of natural gas conserved as a result of such evaluation, and an estimate of the cost, if non-negligible, to optimize operating pressures.

95. Within 120 Days of completion of the POR, Kerr-McGee may identify in writing to EPA, and as applicable CDPHE, any areas of non-compliance with the Act and the Colorado Act (including federal and state implementing regulations) that are discovered during the POR.

Under this Paragraph, for other than PSD/NSR, Kerr-McGee shall include in its written submission: (1) a certification pursuant to Paragraph 112 that it has subsequently complied with all applicable statutory and regulatory requirements, or it shall propose a schedule for coming into compliance; (2) a description of the corrective measures taken, or proposed to be taken; and (3) a proposed calculation of any economic benefit pursuant to the EPA Stationary Source Civil Penalty Policy and BEN Model. EPA and/or CDPHE will review Kerr-McGee's certifications, and/or proposed schedule for compliance, corrective measures, and economic benefit calculation(s), and will respond with written concurrence or comments. In the event that EPA and/or CDPHE do not approve of the proposed corrective measures or economic benefit calculation(s), each, as applicable, will respond with written comments. Should EPA and/or CDPHE still not agree with the economic benefit calculation(s), EPA and/or CDPHE's independent economic benefit calculations shall be final and payable. If necessary, the Parties will address any PSD/NSR violations as a new and separate enforcement action. Kerr-McGee's release from liability as specified in Section XVII (Effect of Settlement/Reservation of Rights) for the areas of non-compliance identified and corrected pursuant to this Section IX will take effect upon the Plaintiffs' written concurrence with Kerr-McGee's certification and its payment in full of any economic benefit. Any areas of non-compliance discovered by EPA or CDPHE, and any disclosures by Kerr-McGee beyond this specific 120-Day period, are not covered by this provision.

X. CIVIL PENALTY

96. Within 30 Days after the Effective Date of this Consent Decree, Kerr-McGee shall pay to the Plaintiffs a total civil penalty pursuant to Section 113 of the Act, 42 U.S.C. §

7413, in the amount of $200,000, with interest accruing from the date on which the Consent Decree is entered by the Court at the rate specified in 28 U.S.C. § 1961 as of the date of entry.

97. Federal Payment Instructions: Of the total amount of the civil penalty, Kerr-McGee shall pay $150,000 to the United States. Kerr-McGee shall make payment by Electronic Funds Transfer ("EFT") to the United States Department of Justice ("DOJ"), in accordance with current EFT procedures, referencing the United States Attorney's Office ("USAO") File Number and DOJ Case Number 90-5-2-1-08656. Payment shall be made in accordance with instructions provided by the USAO for the District of Colorado. Any funds received after 11:00 a.m. (EST/EDT) shall be credited on the next business Day. Kerr-McGee shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1-08656 and the civil case name and case number, to DOJ and to EPA, as provided in Section XX (Notices).

98. State Payment Instructions: Of the total amount of the civil penalty, Kerr-McGee shall pay $50,000 to the State. Kerr-McGee shall make payment by certified, corporate or cashier's check drawn to the order of "Colorado Department of Public Health and Environment" and delivered to the attention of Legal Administrative Specialist, Air Pollution Control Division, 4300 Cherry Creek Drive South, APCD-SS-B1, Denver, CO 80246-1530. Kerr-McGee shall provide notice of payment, referencing USAO File Number and DOJ Case Number 90-5-2-1-08656, and the civil case name and case number, to CDPHE, as provided in Section XX (Notices).

99. No amount of the civil penalty to be paid by Kerr-McGee shall be used to reduce its federal or Colorado tax obligations.

XI. SUPPLEMENTAL ENVIRONMENTAL PROJECTS

A. Uintah County Road Dust SEP

100. Subject to approval by the Uintah County Commissioners, Kerr-McGee shall implement a Supplemental Environmental Project ("SEP"), to improve a portion of a County Road in Uintah County, Utah, in the Uinta Basin, to reduce particulate matter (road dust), in accordance with the provisions of Appendix M (the "Road Dust SEP"). The Road Dust SEP shall be completed within 12 months after entry of this Decree. In implementing the Road Dust SEP, Kerr-McGee shall spend not less than $100,000 in eligible Road Dust SEP costs. Eligible Road Dust SEP costs include the costs of planning and implementing the Road Dust SEP, or contracting for the work through the Uintah County Roads Department.

101. Kerr-McGee is responsible for the satisfactory completion of the Road Dust SEP in accordance with the requirements of this Consent Decree. Kerr-McGee may use contractors or consultants in planning and implementing the Road Dust SEP or coordinating such planning and implementation by the Uintah County Roads Department. "Satisfactory completion" means completion of the work in accordance with all work plans and specifications for the project and expenditure of not less than $100,000.

B. Accelerated Vehicle Retirement State SEP

102. No later than 30 Days after the Effective Date of this Consent Decree, Kerr-McGee shall implement a SEP to reduce air pollution from high-emitting vehicles in the Denver metropolitan area (the "Accelerated Vehicle Retirement State SEP") by transferring $150,000 ("SEP Funds") to the Regional Air Quality Council ("RAQC"). The criteria, terms and procedures for the Accelerated Vehicle Retirement State SEP are described in Appendix N. The

transfer of funds to the RAQC shall be by certified, corporate or cashiers check made payable to the Regional Air Quality Council and delivered to the attention of Steve McCannon, Program Manager, Regional Air Quality Council, 1445 Market St., Suite 260, Denver, CO 80202. Prior to transferring the funds, Kerr-McGee shall obtain a written statement from the RAQC acknowledging and agreeing that the RAQC will expend the SEP Funds to implement the Accelerated Vehicle Retirement State SEP in accordance with the criteria, terms and procedure described in Appendix N. Within 10 days of transferring the SEP Funds, Kerr-McGee will provide a copy of the check and the RAQC's written statement to CDPHE.

C. General Requirements

103. With regard to both the Road Dust SEP and the Accelerated Vehicle Retirement State SEP, Kerr-McGee certifies the truth and accuracy of each of the following:

a. that, as of the date of executing this Decree, Kerr-McGee was not required to perform or develop either SEP by any federal, state, or local law or regulation and was not required to perform or develop the SEPs by prior agreement, grant, or as injunctive relief awarded in any other action in any forum;

b. that neither SEP is a project that Kerr-McGee was planning or intending to construct, perform, or implement other than in settlement of the claims resolved in this Decree;

c. that Kerr-McGee has not received and will not receive credit for either SEP in any other enforcement action by a government entity; and

d. that Kerr-McGee will not receive any reimbursement for any portion of the SEP costs from any other person.

104. SEP Completion Reports: Within 30 Days after the date set for completion of each SEP, Kerr-McGee shall submit a SEP Completion Report to the United States, and with regard to the Accelerated Vehicle Retirement State SEP also to CDPHE, in accordance with Section XIX (Notices) of this Consent Decree. The SEP Completion Reports shall contain the following information:

a. a detailed description of the SEP, as implemented;

b. a description of any problems encountered in completing the SEP and the solutions thereto;

c. an itemized list of all eligible SEP costs;

d. certification pursuant to Paragraph 112 that the SEP has been fully implemented pursuant to the provisions of this Decree; and

e. a description of the air quality benefits resulting from implementation of the SEP, including an estimate of associated emission reductions.

105. EPA, or as applicable CDPHE, may require information in addition to that described in the preceding Paragraph 104, which is reasonably necessary to determine satisfactory completion of the SEPs or eligibility of SEP costs. Kerr-McGee shall provide such additional information to which it has access.

106. Within 60 Days after receiving each SEP Completion Report, the United States and/or CDPHE shall notify Kerr-McGee whether the SEP at issue has been satisfactorily completed. If a SEP has not been satisfactorily completed in accordance with all applicable

work plans and schedules, or if the amount expended on performance of a SEP is less than the amount set forth in Paragraphs 100 and 102, stipulated penalties may be assessed under Section XIII (Stipulated Penalties) of this Consent Decree.

107. Disputes concerning the satisfactory completion of a SEP and the amount of eligible SEP costs may be resolved under Section XV (Dispute Resolution) of this Consent Decree. No other disputes arising under this Section shall be subject to Dispute Resolution.

108. Each submission required under this Section shall be signed by an official with knowledge of the SEP and shall bear the certification language set forth in Paragraph 112.

109. Any public statement by Kerr-McGee making reference to either SEP, whether oral or written, in print, film, or other media, shall include the following language: "This project was undertaken in connection with the settlement of an enforcement action taken on behalf of the U.S. Environmental Protection Agency and/or the State of Colorado for alleged violations of the Clean Air Act and/or the Colorado Air Pollution Prevention and Control Act."

XII. REPORTING REQUIREMENTS

110. Kerr-McGee shall submit the following reports:

a. All initial performance test results, retest reports, initial status reports, progress reports, final reports, notices, and monitoring data pursuant to any specific requirement of this Consent Decree for each annual reporting period (not a cumulative requirement).

b. By no later than March 1 of each year, Kerr-McGee shall submit an Annual Report for the preceding calendar year to EPA, and for any matters involving the D-J Basin also to CDPHE. Kerr-McGee shall provide a paper and electronic copy of each Annual Report to EPA and, as applicable, CDPHE. The Annual Report shall: (i) describe all work or other activities that Kerr-McGee performed pursuant to any requirement of this Consent Decree during the applicable reporting period; (ii) transmit any specific (non-annual) reports to be included in an Annual Report; (iii) describe compliance status; and (iv) describe any non-compliance with the requirements of this Consent Decree and explain the likely cause(s) of the violation(s) and the remedial steps taken, or to be taken, to prevent or minimize such violation(s).

c. If Kerr-McGee violates, or has reason to believe that it may violate, any requirement of this Consent Decree, Kerr-McGee shall notify EPA, and as applicable CDPHE, of such violation(s), and its likely duration, in writing, within 10 Days of the Day Kerr-McGee first becomes aware of the violation(s), or potential violation(s), with an explanation of the likely cause of such violation(s) and the remedial steps taken, or to be taken, to prevent or minimize such violation(s) should it occur. If the cause of a violation cannot be fully explained at the time the notification is due, Kerr-McGee shall state this in the notice, investigate the cause of each such violation in the event that it occurs, and submit a full written explanation of the cause of the violation within 30 Days of the date that Kerr-McGee determines such cause. Nothing in this Paragraph relieves

Kerr-McGee of its obligation to provide the notice required by Section XIV (Force Majeure).

111. All reports shall be submitted to the persons designated in Section XIX (Notices) of this Consent Decree.

112. Each Annual Report submitted by Kerr-McGee shall be signed by a Responsible Official. All other reports or submissions may be signed by a delegated employee representative, unless otherwise required by applicable statute or regulation. All reports and submissions shall include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete.

113. The reporting requirements of this Section shall continue until termination of this Consent Decree; however, upon written agreement by EPA, or as applicable CDPHE, where a Consent Decree reporting requirement is added to a final Title V permit or other non-Title V permit such that the permit meets or exceeds such Consent Decree reporting requirement, Kerr-McGee may fulfill that Consent Decree reporting requirement by notifying EPA, and as applicable CDPHE, that the required report has been provided pursuant to a permit requirement, and by identifying the relevant permit in Kerr McGee's Annual Reports, submitted pursuant to this Section XII (Reporting Requirements).

114. Any information provided pursuant to this Consent Decree may be used by the United States or as applicable the State in any proceeding to enforce the provisions of this

Consent Decree and as otherwise permitted by law, except for disclosures made pursuant to Paragraph 95 of this Consent Decree.

XIII. STIPULATED PENALTIES

115. Kerr-McGee shall be liable for stipulated penalties to the United States and the State for violations of this Consent Decree as specified below, unless excused under Section XIV (Force Majeure), or reduced or waived by one or both Plaintiffs pursuant to Paragraph 121 of this Decree. A violation includes failing to perform any obligation required by the terms of this Decree, including any work plan or schedule approved under this Decree, according to all applicable requirements of this Decree and within the specified time schedules established by or approved under this Decree.

a. Low-Emission Dehydrators (Section IV.A.).

	Violation	Stipulated Penalty
1.	For failure to provide written notice as required by Paragraph 8 per unit per Day.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
2.	For failure to install and operate Low-Emission Dehydrators at new facilities as required by Paragraph 9.	For each unit: $1,000 per Day for the first 30 Days of noncompliance, $1,500 per Day from the 31st to 60th Day of noncompliance, and $2,000 per Day thereafter.
3.	For failure to provide written notice as required by Paragraph 10.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
4.	For failure to maintain records and information as required by Paragraph 11.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.

b. Condensate Storage Tanks (Section IV.B.).

	Violation	Stipulated Penalty
1.	For failure to install and operate a flare, VRU, or other non-flare alternative as required by Paragraphs 12, 18, & 20.	For each unit: $1,000 per Day for the first 30 Days of noncompliance, $2,500 per Day from the 31st to 60th Day of noncompliance, and $5,000 per Day thereafter.
2.	For failure to submit a worksheet on flare design and certification of compliance as required by Paragraphs 13, 15, 22, & 24.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
3.	For failure to conduct inspections, submit reports, maintain records and apply to amend Title V permit applications as required by Paragraphs 16, 17, 19, 25, 26 & 27.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
4.	For failure to maintain records and information as required by Paragraph 28.	For each unit: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.

c. Compressor Engines (Section IV.C. & D.).

	Violation	Stipulated Penalty
1.	For failure to install emission controls on RICE or alternatively replace with new RICE as required by the dates set forth in Paragraphs 30, 31, 40, & 49.	For each engine: $1,000 per Day for the first 30 Days of noncompliance, $2,500 per Day from the 31st to 60th Day of noncompliance, and $5,000 per Day thereafter.
2.	For failure to conduct initial performance test on the RICE emission controls as required by Paragraphs 35, 43, & 51.	For each engine: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.
3.	For failure to retest and submit a report as required by Paragraphs 36, 44, & 52.	For each engine: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.
4.	For failure to submit an O&M plan as required by Paragraph 37.	$200per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
5.	For failure to conduct semi-annual tests on RICE emission controls on a semi-annual, calendar-year basis as required by Paragraphs 45 & 53.	For each engine: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.
6.	For failure to submit reports as required by Paragraphs 46, 47, 54, & 55.	For each report: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
7.	For failure to maintain records and apply to amend Title V permits as required by Paragraphs 38, 39, 56 & 57.	For each engine: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.
8	For failure to comply with the NOx control requirements and CO destruction efficiency required by Paragraphs 32 and 33.	For each engine: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.

d. Pneumatic Controllers (Section IV.E.).

	Violation	Stipulated Penalty
1.	For failure to complete the first one-half of the Pneumatic Controller retrofits as required by Paragraph 59 in the Uinta Basin (as one project) and in the D-J Basin (as a separate project).	For each project: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.
2.	For failure to complete all the remaining Pneumatic Controller retrofits as required by Paragraph 60 in the Uinta Basin (as one project) and in the D-J Basin (as a separate project).	For each project: $500 per Day for the first 30 Days of noncompliance, $1,000 per Day from the 31st to 60th Day of noncompliance, and $1,500 per Day thereafter.
3.	For failure to provide a final completion report for retrofitting Pneumatic Controllers in the Uinta Basin and the D-J Basin as required by Paragraph 62.	For each project: $100 per Day for the first 30 Days of noncompliance, $250 per Day from the 31st to 60th Day of noncompliance, and $500 per Day thereafter.
4.	For failure to replace high-bleed Pneumatic Controllers in the D-J Basin as required by Paragraph 61.	$100 per Day for the first 30 Days of noncompliance, $250 per Day from the 31st to 60th Day of noncompliance, and $500 per Day thereafter.
5.	For failure to install low or no-bleed Pneumatic Controllers at newly constructed facilities in the Uinta Basin or the D-J Basin as required by Paragraph 63.	For each project: $100 per Day for the first 30 Days of noncompliance, $250 per Day from the 31st to 60th Day of noncompliance, and $500 per Day thereafter.
6.	For failure to implement Appendix I and maintain records as required by Paragraphs 64 & 65.	For each project: $200 per Day for the first 30 Days of noncompliance, $500 per Day from the 31st to 60th Day of noncompliance, and $1,000 per Day thereafter.

e. Sulfur Removal Technology (Section IV.F.).

	Violation	Stipulated Penalty
1.	For failure to install and operate liquid-bed sulfur removal technology in the Uinta Basin as required by Paragraph 66.	For each unit: $1,000 per Day for the first 30 Days of noncompliance, $2,500 per Day from the 31st to 60th Day of noncompliance, and $5,000 per Day thereafter.
2.	For failure to submit notification of each installation as required by Paragraph 67.	For each unit: $100 per Day for the first 30 Days of noncompliance, $200 per Day from the 31st to 60th Day of noncompliance, and $500 per Day thereafter.
3.	For failure to maintain records as required by Paragraph 68.	For each unit: $100 per Day for the first 30 Days of noncompliance, $250 per Day from the 31st to 60th Day of noncompliance, and $500 per Day thereafter.

f. Administrative Requirements (Section V).

	Violation	Stipulated Penalty
1.	For failure to submit a proposed O&M plan as required by Paragraph 69.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
2.	For failure to timely implement the approved O&M plan as required by Paragraph 71.	\$500 per Day for the first 30 Days of noncompliance, \$1,000 per Day from the 31st to 60th Day of noncompliance, and \$1,500 per Day thereafter.
3.	For failure to submit a proposed permit amendment for a consolidated allowable VOC limit for the Fort Lupton Facility as required by Paragraph 72.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
4.	For failure to apply to amend the Title V permit as required by Paragraph 73.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
5	For failure to comply with the interim emission limit established in Paragraph 73.	\$500 per Day for the first 30 Days, \$1,000 per Day for the 31st to 60th Day, and \$1,500 per Day thereafter

g. Ambient Air Monitoring (Section VII).

	Violation	Stipulated Penalty
1.	For failure to fund the purchase of ambient air monitoring station(s) as required by Paragraph 80.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.

h. Multi-Phase Piping/Tankless Well-Site Pilot Project (Section VIII).

	Violation	Stipulated Penalty
1.	For failure to complete the Feasibility Study, submit a written Feasibility Study report, submit a proposed SOW for the implementation of the Multi-Phase Pilot, or provide an Added Incremental Cost report as required by Paragraphs 83, 84, & 85, per deliverable.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
2.	For failure to submit a semi-annual progress report as required by Paragraph 87.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
3.	For failure to implement and complete the Multi-Phase Pilot as required by Paragraphs 86 & 88.	\$500 per Day for the first 30 Days of noncompliance, \$1,000 per Day from the 31st to 60th Day of noncompliance, and \$1,500 per Day thereafter.
4.	For failure to submit a final report as required by Paragraph 89.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
5.	For failure to maintain records as required by Paragraph 90.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.

i. Performance Optimization Review (Section IX).

	Violation	Stipulated Penalty
1.	For failure to complete the POR by the date specified in Paragraph 91 for either the Uinta Basin or the D-J Basin, as separate projects.	For each project: \$500 per Day for the first 30 Days of noncompliance, \$1,000 per Day from the 31st to 60th Day of noncompliance, and \$1,500 per Day thereafter.
2.	For failure to submit a POR report as required by Paragraph 94.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.

j. SEPs (Section XI).

	Violation	Stipulated Penalty
1.	For failure to transfer funds to the Uintah County Road Department by the date specified in Paragraph 100.	For each project, \$500 per Day for the first 30 Days of noncompliance, \$1,000 per Day from the 31st to 60th Day of noncompliance, and \$1,500 per Day thereafter
2.	For failure to transfer SEP Funds to the RAQC by the date specified by Paragraph 102.	For each project, \$500 per Day for the first 30 Days of noncompliance, \$1,000 per Day from the 31st to 60th Day of noncompliance, and \$1,500 per Day thereafter
3.	For failure to submit a report as required by 104.	\$200 per Day for the first 30 Days of noncompliance, \$500 per Day from the 31st to 60th Day of noncompliance, and \$1,000 per Day thereafter.
4.	For failure to spend at least the amounts set forth in Paragraphs 100 or 102.	For each SEP, an amount equal to the difference between the amount of total eligible SEP costs expended and the amount set forth in Paragraphs 100 or 102.

116. Late Payment of Civil Penalty: If Kerr-McGee fails to pay the civil penalty required to be paid under Section X (Civil Penalty) of this Consent Decree to the United States

or as applicable the State, when due, Kerr-McGee shall pay a stipulated penalty of $1,000 per Day for each Day that the payment is late.

117. Stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree.

118. Kerr-McGee shall pay any stipulated penalty within 30 Days of receipt of written demand of the United States, or as applicable the State, and shall continue to make such payments every 30 Days thereafter until the violation(s) no longer continue, unless Kerr-McGee elects within 20 Days of receipt of written demand from the United States, or as applicable the State, to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

119. For violations that concern or relate to facilities in the Uinta Basin, Kerr-McGee shall pay the total amount of stipulated penalties to the United States. For violations that concern or relate to facilities in the D-J Basin, Kerr-McGee shall pay 40 percent to the United States and 60 percent to the State.

120. Kerr-McGee shall pay stipulated penalties in accordance with the federal and state payment instructions set forth in Paragraphs 97 and 98.

121. The United States or the State may, in the unreviewable exercise of their respective discretion, reduce or waive stipulated penalties otherwise due such Plaintiff under this Consent Decree. The determination by one Plaintiff not to seek stipulated penalties, or

subsequently to waive or reduce the amount it seeks, shall not preclude the other Plaintiff from seeking the full amount of stipulated penalties owing.

122. Stipulated penalties shall continue to accrue as provided in Paragraph 117 during any dispute, with interest on accrued stipulated penalties payable and calculated by the Secretary of Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, Kerr-McGee shall pay accrued stipulated penalties and accrued interest agreed or determined to be owing within 30 Days of the effective date of such agreement or the receipt of Plaintiffs' decision.

b. If the dispute is appealed to the Court, and the Plaintiffs prevail in whole or in part, Kerr-McGee shall pay all accrued stipulated penalties determined by the Court to be owing, together with accrued interest, within 60 Days of receiving the Court's decision or order, except as provided in Subparagraph c., below.

c. If any Party appeals the Court's decision, Kerr-McGee shall pay all accrued penalties determined by the appellate court to be owing, together with accrued interest, within 15 Days of receiving the final appellate court decision.

123. Kerr-McGee shall not deduct stipulated penalties paid under this Section XIII in calculating its federal or state income tax.

124. Subject to the provisions of Section XVII (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States for Kerr-McGee's violation of this Consent Decree or applicable law. Where a violation of this Consent Decree is also a violation of the Act or regulatory requirements of the Act, or the Colorado Act or the regulatory requirements of the Colorado Act, Kerr-McGee shall be allowed a dollar-for-dollar credit, for any stipulated penalties paid, against any statutory penalties imposed for such violation.

XIV. FORCE MAJEURE

125. If any event occurs which causes or may cause a delay or impediment to performance in complying with any provision of this Consent Decree (*e.g.* would require operation in an unsafe manner), and which Kerr-McGee believes qualifies as an event of *Force Majeure*, Kerr-McGee shall notify the Plaintiffs in writing as soon as practicable, but in any event within 45 Days of when Kerr-McGee first knew of the event or should have known of the event by the exercise of reasonable diligence. In this notice Kerr-McGee shall specifically reference this paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken and/or to be taken by Kerr-McGee to prevent or minimize the delay and the schedule by which those measures will be implemented. Kerr-McGee shall adopt all reasonable measures to avoid or minimize such delays.

126. Failure by Kerr-McGee to substantially comply with the notice requirements of Paragraph 125, as specified above, shall render this Section voidable by the Plaintiffs, as to the

specific event for which Kerr-McGee has failed to comply with such notice requirement. If so voided, this Section shall be of no effect as to the particular event involved.

127. The Plaintiffs shall notify Kerr-McGee in writing regarding their agreement or disagreement with any claim of a Force Majeure event within 45 Days of receipt of each Force Majeure notice provided under Paragraph 125.

128. If the Plaintiffs agree that the delay or impediment to performance has been or will be caused by circumstances beyond the control of Kerr-McGee, including any entity controlled or contracted by it, and that Kerr-McGee could not have prevented the delay by the exercise of reasonable diligence, the Parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay by a period equivalent to the delay actually caused by such circumstances, or such other period as may be appropriate in light of the circumstances. Such stipulation may be filed as a modification to this Consent Decree by agreement of the Parties pursuant to the modification procedures established in this Consent Decree. Kerr-McGee shall not be liable for stipulated penalties for the period of any such delay.

129. If the Plaintiffs do not agree that the delay or impediment to performance has been or will be caused by circumstances beyond the control of Kerr-McGee, including any entity controlled or contracted by it, the position of the Plaintiffs on the Force Majeure claim shall become final and binding upon Kerr-McGee, and Kerr-McGee shall pay applicable stipulated penalties, unless Kerr-McGee submits the matter to this Court for resolution by filing a petition for determination with this Court within 20 business Days after receiving the written notification of the Plaintiffs as set forth in Paragraph 127. In the event that the United States and the State disagree, the position of the United States shall become the Plaintiffs' final position with regard

to Kerr-McGee's Force Majeure claim. Once Kerr-McGee has submitted such matter to this Court, the Plaintiffs shall have 20 business Days to file a response to the petition. If Kerr-McGee submits the matter to this Court for resolution and the Court determines that the delay or impediment to performance has been or will be caused by circumstances beyond the control of Kerr-McGee, including any entity controlled or contracted by Kerr-McGee, and that it could not have prevented the delay by the exercise of reasonable diligence, Kerr-McGee shall be excused as to such event(s) and delay (including stipulated penalties) for all requirements affected by the delay for a period of time equivalent to the delay caused by such circumstances or such other period as may be determined by the Court.

130. Kerr-McGee shall bear the burden of proving that any delay of any requirement(s) of this Consent Decree was (were) caused by or will be caused by circumstances beyond its control, including any entity controlled or contracted by Kerr-McGee, and that it could not have prevented the delay by the exercise of reasonable diligence. Kerr-McGee shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but does not necessarily, result in an extension of a subsequent compliance date or dates. Unanticipated or increased costs or expenses associated with the performance of obligations under this Consent Decree shall not constitute circumstances beyond the control of Kerr-McGee.

131. As part of the resolution of any matter submitted to this Court under this Section, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay or impediment to performance on which an

agreement by the Plaintiffs or approval by this Court is based. Kerr-McGee shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule, except to the extent that such schedule is further modified, extended or otherwise affected by a subsequent Force Majeure event under this Section XIV.

XV. DISPUTE RESOLUTION

132. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree. For any dispute that concerns D-J Basin Facilities, the provisions of this Section apply equally to both the United States and the State, as Plaintiffs.

133. Informal Dispute Resolution: Any dispute subject to Dispute Resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when Kerr-McGee sends the Plaintiff(s) a written Notice of Dispute. Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed 20 Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the Plaintiff(s) shall be considered binding unless, within 20 Days after the conclusion of the informal negotiation period, Kerr-McGee invokes formal dispute resolution procedures as set forth below. In the event that the United States and the State are unable to reach agreement with regard to Kerr-McGee's claim, the position of the United States shall be the Plaintiffs' final position.

134. Formal Dispute Resolution: Kerr-McGee may only invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on

the Plaintiff(s) a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but may not necessarily be limited to, any factual data, analysis, or opinion supporting Kerr-McGee's position and any supporting documentation relied upon by Kerr-McGee.

135. The Plaintiff(s) shall serve its (their) Statement of Position within 30 Days of receipt of Kerr-McGee's Statement of Position. The Plaintiff(s)' Statement of Position shall include, but may not necessarily be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the Plaintiff(s). The Plaintiff(s)' Statement of Position shall be binding on Kerr-McGee, unless Kerr-McGee files a motion for judicial review of the dispute in accordance with Paragraph 136. In the event that the United States and the State are unable to reach agreement with regard to Kerr-McGee's claim, the position of the United States shall be the Plaintiffs' final position.

136. Kerr-McGee may seek judicial review of the dispute by filing with the Court and serving on the Plaintiff(s), in accordance with Section XIV of this Consent Decree (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within 30 Days of receipt of the Plaintiff(s)' Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of Kerr-McGee's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

137. The Plaintiff(s) shall respond to Kerr-McGee's motion within the time period allowed by the Local Rules of the Court. Kerr-McGee may file a reply memorandum, to the extent permitted by the Local Rules and allowed by the Court.

138. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 133, Kerr-McGee shall bear the burden of demonstrating that its position complies with this Consent Decree.

139. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of Kerr-McGee under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of alleged noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 122. If Kerr-McGee does not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section XIII (Stipulated Penalties).

XVI. INFORMATION COLLECTION AND RETENTION

140. The United States, and its representatives, including attorneys, contractors, and consultants, shall have the right of entry into any facility covered by this Consent Decree, and the State, and its representatives, including attorneys, contractors, and consultants, shall have the right of entry into any facility in the D-J Basin subject to any requirement of this Consent Decree, at all reasonable times, upon presentation of credentials, for the purpose of monitoring compliance with any provision of this Consent Decree, including to:

a. monitor the progress of activities required under this Consent Decree;

b. inspect equipment and facilities covered by this Consent Decree; and

c. inspect and copy documents, records, or other information to be maintained in accordance with the terms of this Consent Decree.

141. Kerr-McGee shall be entitled to: (1) splits of samples, where feasible, and (2) copies of any sampling and analytical results, documentary evidence and data obtained by the United States or the State pursuant to Paragraph 140 of this Consent Decree.

142. Until five years after the termination of this Consent Decree, Kerr-McGee shall retain, and shall instruct its contractors and agents to preserve, all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) in its or its contractors' or agents' possession or control, or that come into its or its contractors' or agents' possession or control, and that relate in any manner to Kerr-McGee's performance of its obligations under this Consent Decree. Such documents, records, or other information may be kept in electronic form. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States or the State, Kerr-McGee shall provide copies of any non-privileged documents, records, or other information required to be maintained under this Paragraph.

143. At the conclusion of the information-retention period provided in the preceding Paragraph, Kerr-McGee shall notify the United States and the State at least 90 Days prior to the destruction of any documents, records, or other information subject to the requirements of the preceding Paragraph and, upon request by the United States or the State, Kerr-McGee shall deliver the requested non-privileged documents, records, or other information to EPA or CDPHE.

144. Kerr-McGee may assert that certain documents, records, or other information is privileged under the attorney-client privilege or any other privilege recognized by federal and/or state law. If Kerr-McGee asserts such a privilege, it shall provide the following: (1) the title of the document, record, or information; (2) the date of the document, record, or information; (3) the name and title of each author of the document, record, or information; (4) the name and title of each addressee and recipient; (5) a description of the subject of the document, record, or information; and (6) the privilege asserted by Kerr-McGee. However, no final documents, records or other information that Kerr-McGee is explicitly required to create or generate to satisfy a specific requirement of this Consent Decree shall be withheld on the grounds of privilege.

145. Kerr-McGee may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2 and/or C.R.S. § 25-7-111(4). As to any information that Kerr-McGee seeks to protect as CBI, Kerr-McGee shall follow the procedures set forth in 40 C.F.R. Part 2 and/or C.R.S. § 25-7-111(4).

146. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or the State pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of Kerr-McGee to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XVII. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

147. This Consent Decree resolves all civil claims of the United States and the State for violations alleged in the Complaint and Complaint in Intervention through the date of lodging of this Consent Decree.

148. This Consent Decree further resolves the civil and administrative claims, if any, of the United States and the State for civil penalties and injunctive relief, through the date of lodging of this Consent Decree, under the PSD requirements of Part C of the Act, and the regulations promulgated thereunder at 40 C.F.R. § 52.21 (the "PSD Rules"), and Section 25-7-101 *et seq.* of the Colorado Act, and the regulations promulgated thereunder for:

a. any increase in emissions resulting from the construction by Kerr-McGee's corporate predecessor of the Dougan and Frederick facilities;

b. the disabling of the VRU at the Brighton facility by a Kerr-McGee predecessor and the subsequent failure to operate the VRU;

c. claims that relate to any allegations of engine modifications to RICE located at D-J Basin Facilities, any horsepower discrepancies used to describe RICE in any applicable permit for D-J Basin Facilities, and any failure or error in horsepower documentation to specify appropriate horsepower and related operational parameters for RICE located at D-J Basin Facilities.

149. This Consent Decree resolves the civil claims of the United States and the State for violations disclosed under Paragraph 95, except for non-compliance that would trigger PSD/NSR.

150. The United States and the State reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree, except as expressly stated in Paragraphs 147-149. This Consent Decree shall not be construed to limit the rights of the United States or the State to obtain penalties or injunctive relief under the Act or Colorado Act or their implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly provided in Section VI (Limits on Potential to Emit), and Paragraphs 147 - 149.

151. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. Nothing in this Consent Decree shall relieve Kerr-McGee of its obligation to achieve and maintain full compliance with all applicable federal, State, and local laws, regulations, and permits. Kerr-McGee's compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as otherwise provided in Paragraphs 147-149. The United States and the State do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Kerr-McGee's compliance with any aspect of this Consent Decree will result in compliance with other provisions of the Act, the Colorado Act, or their implementing regulations or with any other provisions of federal, State, or local laws, regulations, or permits.

152. This Consent Decree does not limit or affect the rights of Kerr-McGee or of the United States or the State against any third parties, not party to this Consent Decree, nor does it limit the rights of third parties, not party to this Consent Decree, against Kerr-McGee, except as provided herein and as otherwise provided by law.

153. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not a party to this Consent Decree.

XVIII. EMISSION REDUCTION CREDIT GENERATION

154. Kerr-McGee shall not generate or use any NOx, CO, VOC or SO_2 emission reductions that result from any projects conducted pursuant to this Consent Decree as credits or offsets in any PSD, major non-attainment and/or minor New Source Review ("NSR") permit or permit proceeding. The foregoing notwithstanding, Kerr-McGee may conduct projects pursuant to this Consent Decree that create more emission reductions of NOx, CO, VOCs or SO_2 than are required for these pollutants by the underlying applicable requirement(s). In such instances, Kerr-McGee may retain a portion of the achieved emissions reductions for use as credits or offsets. All other emission sources of NOx, CO, VOCs or SO_2, and any netting associated with other pollutants, are outside the scope of these netting limitations and are subject to PSD/NSR applicability as implemented by the appropriate permitting authority or EPA. Use of emission reductions in netting and as offsets in any PSD, major non-attainment and/or minor NSR permit or permit proceeding pursuant to the limitations herein shall be further limited by the applicable regulations, and by the PSD, major non-attainment, and/or minor NSR permit(s) in question, as applicable.

XIX. COSTS

155. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and the State shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties if due.

XX. NOTICES

156. Unless otherwise specified herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and mailed or hand delivered addressed as follows:

As to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
Re: DOJ No. 90-5-2-1-08656

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

and

Assistant Regional Administrator
Office of Enforcement, Compliance, and Environmental Justice
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

As to the State of Colorado:

Director
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South
Denver, CO 80246-1530

As to Kerr-McGee:

Vice President
Kerr-McGee Corporation
1099 18th Street
Denver, CO 80202

and

Director, Environmental, Health and Safety, Rocky Mountain Region
Kerr-McGee Corporation
1099 18th Street
Denver, CO 80202

157. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above.

158. Notices submitted by mail pursuant to this Section XX shall be deemed submitted upon mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XXI. SALES OR TRANSFERS OF OWNERSHIP/OPERATOR INTERESTS

159. If Kerr-McGee proposes to sell or transfer all or part of its ownership or its responsibility as operator of any of the Uinta Basin Facilities, D-J Basin Facilities, or any other facilities that are subject to any requirement of this Consent Decree, except for individual wells

or groups of wells and associated wellhead facilities, to any entity unrelated to the Defendant ("Third Party"), Kerr-McGee shall advise the Third Party in writing of the existence of this Consent Decree prior to such sale or transfer and shall send a copy of such written notification to the Plaintiffs pursuant to Section XX (Notices) of this Consent Decree at least 60 Days before such proposed sale or transfer.

160. No sale or transfer of ownership to a Third Party shall take place before the Third Party consents in writing, by a stipulation to be filed with the Court, to: (a) accept all of the obligations, terms and conditions of this Consent Decree applicable to Uinta Basin Facilities or D-J Basin Facilities, or any other facilities, exclusive of wellhead facilities, that are subject to any requirement of this Consent Decree; (b) the jurisdiction of the Court to enforce the terms of this Consent Decree as to such party; and (c) become a party to this Consent Decree. Notwithstanding such a sale or transfer to a Third Party, Kerr-McGee shall remain jointly and severally liable with the Third Party unless the Consent Decree is modified or Kerr-McGee's joint and several liability is restricted in accordance with Paragraph 161.

161. If the United States, and as applicable the State, agrees, the Parties and the Third Party may execute a modification to this Consent Decree that relieves Kerr-McGee of its liability under this Consent Decree for, and makes the Third Party liable for, all obligations and liabilities applicable to the purchased or transferred facilities or operator responsibility. Notwithstanding the foregoing, Kerr-McGee may not assign, and may not be released from, obligations under this Consent Decree to pay the civil penalty in accordance with Section X (Civil Penalty), undertake the Supplemental Environmental Projects in accordance with Section XI (Supplemental Environmental Projects), pay stipulated penalties with respect to actions occurring prior to the

date of transfer of ownership or operator responsibility in accordance with Section XIII (Stipulated Penalties), or maintain documents or provide reports with respect to those obligations in accordance with Sections XII (Reporting Requirements) and XVI (Information Collection and Retention). Kerr-McGee may propose, and the United States and as applicable the State, may agree to restrict the scope of the joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the transferred or purchased facilities or operator responsibility, to the extent such obligations may be adequately separated in an enforceable manner.

XXII. EFFECTIVE DATE

162. Unless otherwise specifically provided herein, the Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXIII. RETENTION OF JURISDICTION

163. The Court shall retain jurisdiction over this case until termination of this Consent Decree, for the purpose of resolving disputes arising under this Decree pursuant to Section XV (Dispute Resolution) or entering, partially terminating or terminating orders modifying this Decree, pursuant to Sections XXI (Sales or Transfers of Ownership/Operator Interests) XXIV (Modification) and XXV (Termination), or otherwise effectuating, or enforcing compliance with, the terms of this Consent Decree.

XXIV. MODIFICATION

164. The terms of this Consent Decree, including any attached appendices, may be modified only by a subsequent written agreement signed by all the Parties. With respect to any modification that constitutes a material change to this Decree, such written agreement shall be

filed with the Court and effective only upon the Court's approval. Any modification of a reporting requirement of this Consent Decree shall be deemed a non-material modification. Any disputes concerning modification of this Decree shall be resolved pursuant to Section XV (Dispute Resolution) of this Consent Decree.

XXV. TERMINATION

165. This Consent Decree shall remain in effect until terminated or partially terminated in accordance with the provisions of this Section.

166. Kerr-McGee shall serve upon the United States and the State a Request for Termination after January 1, 2017. The Request for Termination shall certify that Kerr-McGee has paid the civil penalty and all stipulated penalties, if any, that have accrued, and has fulfilled all other obligations of this Consent Decree.

167. Where a control requirement, recordkeeping requirement, reporting requirement or other requirement of this Consent Decree is incorporated into a federally enforceable permit, Kerr-McGee may serve upon the United States and the State a Request for Partial Termination. Upon approval of such request by the Plaintiffs, the filing of a joint stipulation by the Parties and the Court's approval in accordance with Paragraph 168, the Consent Decree provision in question shall be superseded by the corresponding permit provision, which shall govern as the applicable requirement.

168. Following receipt by the United States and the State of Kerr-McGee's Request for Termination or Partial Termination, the Parties shall confer informally concerning the Request for Termination or Partial Termination and any disagreement that the Parties may have as to whether Kerr-McGee has satisfactorily complied with the requirements for termination of this

Consent Decree. If the United States and the State agree that the Decree may be terminated or partially terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating or partially terminating the Decree.

169. If the United States or the State does not agree that the Decree may be terminated, Kerr-McGee may immediately appeal the disposition of its Request for Termination to the Court.

XXVI. PUBLIC PARTICIPATION

170. This Consent Decree shall be lodged with the Court for a period of not less than 30 Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States and the State reserve the right to withdraw or withhold their respective consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. Kerr-McGee consents to entry of this Consent Decree without further notice and agrees not to withdraw from or oppose entry of this Consent Decree by the Court or to challenge any provision of the Consent Decree, unless the United States or the State has notified Kerr-McGee in writing that it no longer supports entry of the Consent Decree.

XXVII. SIGNATORIES/SERVICE

171. Each undersigned representative of Kerr-McGee, the Director, Air Pollution Control Division, CDPHE, and the Assistant Attorney General for the Environment and Natural Resources Division of DOJ certifies that he or she is fully authorized to enter into this Consent Decree and to execute and legally bind the Party he or she represents to the terms and conditions of this document.

172. Kerr-McGee represents that it has authority to legally obligate any of its corporate subsidiaries or affiliates that own or operate any of the Uinta Basin Facilities, the D-J Basin

Facilities, or any other natural gas production or gathering facilities subject to any work or compliance requirements of this Consent Decree, including but not limited to Kerr-McGee Oil and Gas Onshore LP, Westport Field Services LLC, Kerr-McGee (Nevada) LLC, and Kerr-McGee Gathering LLC, to take all actions necessary to comply with the provisions of this Consent Decree.

173. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis. Kerr-McGee agrees to accept service of process by mail pursuant to the provisions of Section XX (Notices) with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVIII. INTEGRATION

174. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement of matters addressed in the Decree, and supersedes all prior agreements and understandings, whether oral or written, concerning such matters. Other than the appendices listed in Section XXX (Appendices), which are attached to and incorporated in this Decree, and deliverables that are subsequently submitted and approved pursuant to this Decree, no other document, representation, inducement, agreement, understanding, or promise constitutes any part of this Decree or the settlement it memorializes, nor shall evidence of any such document, representation, inducement, agreement, understanding or promise be used in construing the terms of this Decree.

XXIX. FINAL JUDGMENT

175. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States, the State, and Kerr-McGee.

XXX. APPENDICES

176. The following appendices are attached to and incorporated into this Consent Decree:

"Appendix A" lists the D-J Basin Facilities.

"Appendix B" lists the Uinta Basin Facilities.

"Appendix C" is the Description of Low-Emission Dehydrators.

"Appendix D" is the Protocol for RICE Compliance Demonstration in the D-J Basin.

"Appendix E" lists the Existing >500 hp RICE at Minor Sources in the Uinta Basin to be Controlled with Oxidation Catalysts.

"Appendix F" is the Protocol for RICE Compliance Demonstration in the Uinta Basin.

"Appendix G" lists the High-Bleed Pneumatic Controllers in the Uinta Basin to be Retrofitted with Low-Bleed Pneumatic Controllers.

"Appendix H" lists the High-Bleed Pneumatic Controllers in the D-J Basin to be Retrofitted with Low-Bleed Pneumatic Controllers.

"Appendix I" is the Kerr-McGee Management Directive Regarding Low-Bleed Pneumatic Controllers in New Construction.

"Appendix J" is the Emission Calculation Methodology for the Fort Lupton facility.

"Appendix K" is the Scope of Work for the Feasibility Study of the Multi-Phase Piping/Tankless Well-Site Pilot Project.

"Appendix L" is the Scope of Work for the Performance Optimization Review Project.

"Appendix M" is the Scope of Work for the Road Dust SEP.

"Appendix N" is the Scope of Work for the Accelerated Vehicle Retirement State SEP.

Dated and entered this _____Day of _____________, 2007

____
UNITED STATES DISTRICT JUDGE
District of Colorado

FOR PLAINTIFF, UNITED STATES OF AMERICA

Date 5/15/07

MATTHEW J. McKEOWN
Acting Assistant Attorney General
Environment & Natural Resources Division
950 Pennsylvania Avenue, N.W.
Room 2143
Washington, D.C. 20530

Date

JEREL ("JERRY") L. ELLINGTON
DIANNE S. SHAWLEY 5/16/07
Senior Counsel
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
1961 Stout Street – 8th Floor
Denver, CO 80294
Telephone (303) 844-1363
Fax (303) 844-1350

Date

TROY A. EID
United States Attorney for the District of Colorado
U.S. Attorney's Office
1225 17th Street #700
Denver, Colorado 80202
Telephone (303) 454-0100
Fax (303) 454-0400

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY

_______________________________ Date____________________

GRANTA Y. NAKAYAMA
Assistant Administrator
Office of Enforcement and Compliance
Assurance
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

FOR PLAINTIFF-INTERVENOR, THE STATE OF COLORADO

_______________________________ Date___________________

PAUL TOURANGEAU
Director, Air Pollution Control Division
Colorado Department of Public Health & Environment
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530
Telephone: (303)-692-3114
Fax: (303) 782-5493

_______________________________ Date___________________

STEPHEN M. BROWN
Assistant Attorney General
Natural Resources and Environmental Section
Colorado Department of Law
1525 Sherman Street, 7th Floor
Denver, Colorado 80203
Telephone: (303) 866-4434
Fax: (303) 866-3558

FOR DEFENDANT, KERR-McGEE CORPORATION

_______________________________ Date___________________

JAMES J. KLECKNER
Vice President
Kerr-McGee Corporation
1099 18th Street
Denver, Colorado 80202
Telephone: (303) 575-0167
Fax: (303) 607-3462

APPENDIX A

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

D-J Basin Facilities

Overview and Purpose

Kerr-McGee has defined D-J Basin Facilities as part of a settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation,* (hereafter the "Consent Decree").

D-J Basin Facilities

Facility	Legal Location	Title V Permit	Construction Permits
Brighton Compressor Station	Sec 29, T1S, R65W, Adams County, Colorado	Title V - 96OPAD164	
Dougan Compressor Station	Sec 14, T1N, R66W, Weld County, Colorado	Title V - 95OPWE033	
Fort Lupton Compressor Station	Sec 14, T2N, R66W, Weld County, Colorado	Title V - 95OPWE013	01WE0763, 01WE0370, 03WE1152, 00WE0582, 00WE0583
Frederick Compressor Station	Sec 15, T1N, R67W, Weld County, Colorado	Title V - 95OPWE035	
Hambert Compressor Station	Sec 36, T4N, R66W, Weld County, Colorado	Title V - 96OPWE165	96WE216-1, 96WE216-2, 96WE216-3
Hudson Compressor Station	SWSW 1/4 Sec 23, T2N, R65W, Weld County, Colorado	Title V - 95OPWE057	
Platteville Compressor Station	SE 1/4 Sec 13, T3N, R66W, Weld County, Colorado	Not Applicable (not a Title V source)	99WE0175, 99WE0176, 01WE0399, 01WE0400, 02WE0126, 99WE0178, 04WE0578

APPENDIX B

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

Uinta Basin Facilities

Overview and Purpose

Kerr-McGee has defined Uinta Basin Facilities as part of a settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation*(hereafter the "Consent Decree").

Uinta Basin Facilities

Uinta Basin Facility	Legal Location	Title V Permit
Bridge Compressor Station	NENE ¼ Section 17, T9S, R22E, Uintah County, Utah	Pending Part 71 permit
Cottonwood Compressor Station	NWNW ¼ Section 27, T9S, R21E, Uintah County, Utah	Pending Part 71 permit
Ouray Compressor Station	NENE ¼ Section 1, T9S, R21E, Uintah County, Utah	Pending Part 71 permit

APPENDIX C

to the

Consent Decree

in the matter of

<u>United States of America and the State of Colorado v. Kerr-McGee Corporation</u>

LOW-EMISSION DEHYDRATOR SPECIFICATIONS

Overview and Purpose

Kerr-McGee has agreed to employ "Low-Emission Dehydrator" technology at its existing and planned facilities in the Uinta Basin as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.A., this Appendix C includes:

(a) a description of physical electrical hard-wiring between the vapor recovery unit ("VRU") compressor(s) and the glycol circulation pumps employed or to be employed, so that if the VRU compressor(s) go down then the glycol circulation pump(s) also shut down, thereby halting the circulation of glycol through the wet gas, as well as the emissions associated with the regeneration of the glycol;

(b) a description of a second level of protection (redundancy) incorporated into a Programmable Logic Controller that uses instrumentation to shut down the glycol dehydration system in the event all VRU compressor(s) go down; and

(c) a description of any third level of protection and discussion of how the non-condensible gases from glycol dehydrator operation shall be piped exclusively to the station inlet or fuel system for use as fuel and is not used for blanket gas in storage tanks or otherwise vented.

Background

Natural gas often contains water vapor at the wellhead which must be removed to avoid pipeline corrosion and solid hydrate formation. Glycol dehydration is the most widely used natural gas dehumidification process. In a glycol dehydration system, dry triethylene glycol ("TEG") or ethylene glycol ("EG") is contacted with wet natural gas. The glycol absorbs water from the natural gas, but also absorbs hydrocarbons including volatile organic compounds ("VOCs") and certain hazardous air pollutants ("HAPs"). Pumps circulate the glycol from a low-pressure distillation column for regeneration back to high pressure in order to contact with the high pressure wet gas. As the wet glycol pressure is reduced prior to distillation, much of the absorbed hydrocarbon is released, including some of the VOCs and HAPs. A flash tank is typically utilized to separate these vapors at a pressure where they can be utilized for fuel. Distillation removes the absorbed water along with any remaining hydrocarbon, including VOCs and HAPs, from the glycol to the still column vent as overhead vapor. Conventional dehydrator still columns often emit the non-condensable portion of this overhead vapor directly to the atmosphere, or to a combustion device such as a thermal oxidizer or reboiler burner.

Kerr-McGee currently utilizes low-emission glycol dehydrators at its facilities in the Uinta Basin. These units capture the non-condensable portion of still vent and flash tank vapors and recompress the vapor with reciprocating or scroll compressors that route the

vapor to the station inlet as natural gas product, to fuel lines for power generation turbines or to the station fuel system. They also employ electric glycol circulation pumps, and except for the recompression of non-condensable vapors, resemble conventional glycol dehydrators in their configuration. See Figure 1.

To insure that the non-condensable vapor compression system is fully integrated into dehydrator operation such that the units cannot be disabled so as to operate while venting to the atmosphere, each unit;

a. incorporates an integral vapor recovery function that prevents the dehydrator from operating independent of the vapor recovery function;
b. either returns the captured vapors to the inlet of the facility where each glycol dehydrator is located or routes the captured vapors to that facility's fuel gas supply header; and
c. thereby emits no more than 1.0 ton per year of VOCs.

Description of Interlocks

The low-emission glycol dehydrators have at least three (3) levels of protection to prevent emissions from occurring.

(a) Physical electrical hard-wiring between the vapor recovery unit (VRU) compressor(s) and the glycol circulation pumps ensures that if the VRU compressor(s) goes down, the glycol pump(s) also shut down, thereby halting the circulation of glycol through the wet gas as well as the emissions associated with the regeneration of glycol. More specifically:

1. Loss of station power interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor.
2. Loss of 24 volt power to a relay interrupts the 480 volt power to the glycol pump(s) circulating glycol through the contactor. The 24 volt power is wired in parallel through the run status contacts of each VRU compressor in a specific service. If all VRU compressors in each specific service are shutdown, the 24 volt power is interrupted. There is at least one spare VRU compressor in standby mode for each specific service at existing Uinta Basin facilities engaged in gas dehydration. Non-condensable gas from VRU compressor discharge always has an outlet because if the station inlet pressure rises to a level greater than VRU compressor output, the flash tank vapors automatically go through a back pressure regulator to the fuel gas system until gathering pressure is reduced.
3. If the glycol still column/reboiler pressure rises above pressure set points, the 24 volt power to a relay is interrupted. The unpowered relay interrupts the 480 volt power to the glycol pump(s) circulating glycol to the contactor. If one of the glycol still VRU compressors is running but not compressing vapors, the pressure switch will detect the pressure rise in the still and shutdown the glycol circulating pump(s).

4. The operation of at least one of the VRU compressors is required to complete the electrical circuit and allow one of the glycol circulation pumps to operate.
5. There is a 10 second time delay switch installed in the physical electrical circuit that must time out before the glycol circulating pump(s) shut down for causes 2 and 3 above. This allows for switching of compressors and helps to prevent false shutdowns.
6. Everything is hard wired and does not depend on any type of controller.

(b) A second level of protection redundancy has been incorporated by utilizing the station Programmable Logic Controller (PLC) to shut down the dehydration system in the event the VRU compressor(s) go down.

1. A PLC timer will start counting when none of the VRU compressor(s) are in operation. When the timer times out, the PLC will not allow the regenerator system to be in run status.

(c) A third level of protection is the routing of non-condensables directly to combustion devices in the stations that utilize micro-turbine electrical generators or central heat medium systems.

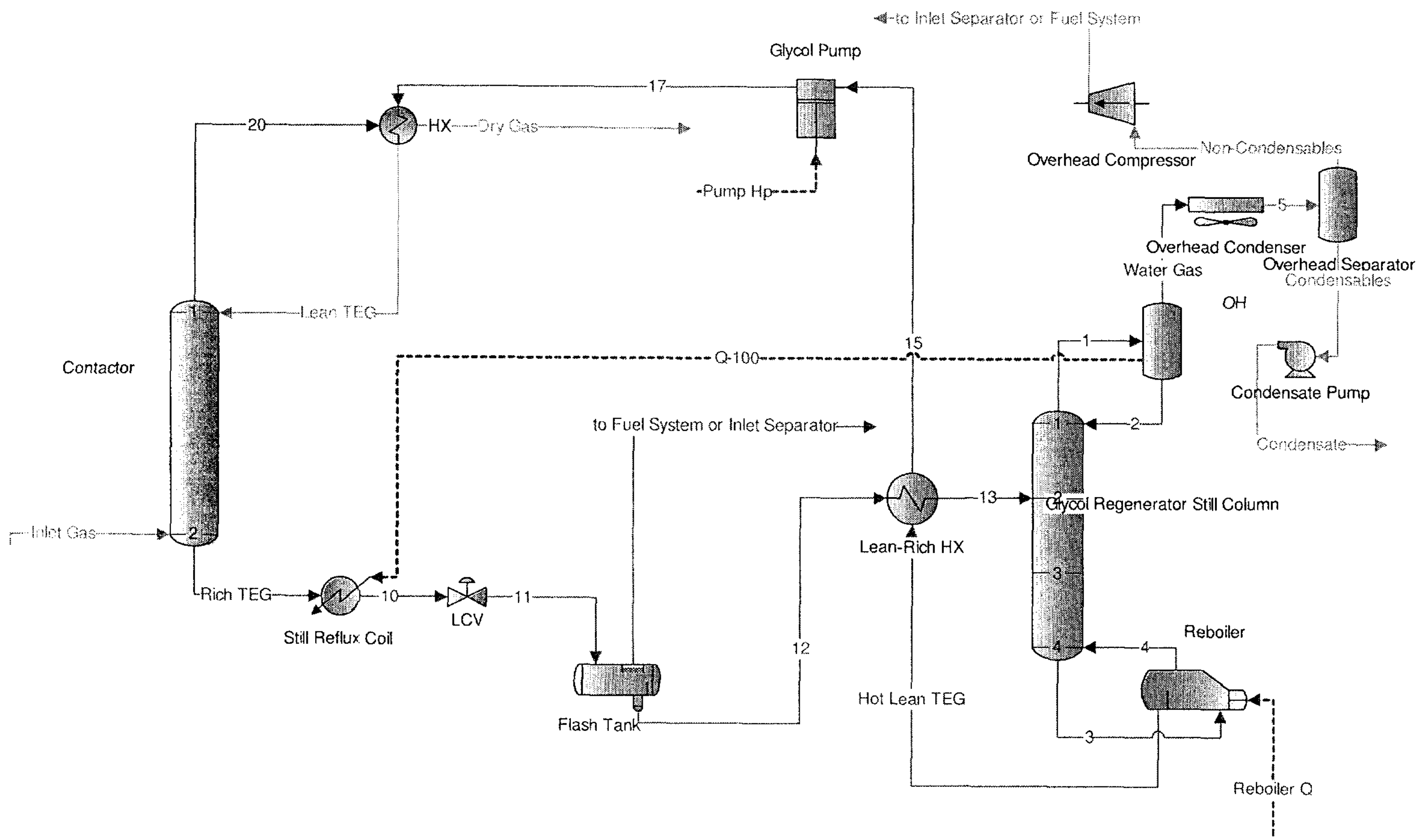
1. The non-condensable regenerator overhead vapors are routed to the inlet of each station or used as fuel. In instances where the inlet pressure rises above VRU compressor outlet pressures, a regulator opens allowing the VRU-compressed vapors to be discharged into the fuel system, where they are used throughout the station.
2. In Kerr-McGee's planned electrified compressor stations, liquids that condense at the compression stations, including those condensed from the glycol still overhead vapors, will be contained at pressure, separated from any water and pumped downstream into the high pressure gathering system. This process change will eliminate atmospheric storage of hydrocarbon liquids at such facilities.

Conclusion

Kerr-McGee's adherence to these specifications shall satisfy its commitment in the Consent Decree to utilize low-emission dehydrator technology in its existing and planned Uinta Basin operations.

Figure 1: Kerr-McGee Low-Emission Dehydrator Schematic

Glycol Dehydration Unit



APPENDIX D

to the

Consent Decree

in the matter of

<u>United States of America and the State of Colorado v. Kerr-McGee Corporation</u>

PROTOCOL FOR INITIAL RICE COMPLIANCE DEMONSTRATION IN THE D-J BASIN

Overview and Purpose

Kerr-McGee has agreed to conduct initial testing on the reciprocating internal combustion engines ("RICE") at certain facilities in the D-J Basin as part of a settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.C., Kerr-McGee will conduct initial emission testing on each of the eleven 2SLB RICE at the Frederick, Dougan, Fort Lupton and Hudson Facilities.

Test Summary

For each 2SLB RICE located at the Frederick, Dougan, and Hudson Facilities, emissions testing will consist of three 60-minute test runs at the engine exhaust stack in accordance with EPA Reference Methods 1, 2, 3A, 4, 7E, 10, and 320 (or 323) for the determination of stack gas flow rate, oxygen (O_2), carbon dioxide (CO_2), stack gas moisture content (H_2O), nitrogen oxides (NO_x), carbon monoxide (CO) and formaldehyde (HCHO). For each 2SLB RICE located at the Fort Lupton Facility all above mentioned methods with the exception of 7E shall be conducted. EPA Reference Methods are given in *40 CFR Part 60, Appendix A*. Stack gas flow rate will be determined in units of dry standard cubic feet per minute (dscfm). Emission concentrations of O_2 and CO_2 will be determined in units of dry volume percent (%vd). Stack gas moisture content will be determined in units of wet volume percent (%vw). Emission concentrations of NO_x and CO will be determined in units of parts per million, dry volume (ppmvd). Emission concentrations of formaldehyde will be determined in units of ppmvw and combined with stack gas moisture data to convert to units of ppmvd. All pollutant concentration data will be combined with stack gas emission rate data to determine pollutant mass emission rates in units of pounds per hour (lb/hr) and tons per year (tpy). Fuel consumption data or EPA Method 19 will be used to calculate mass emission rates in units of pounds of NO_x, CO and HCHO per million British thermal units (lb/mmBtu) for comparison to applicable emission limits.

Concurrent with each 60-minute outlet test run, a 60-minute test will be performed upstream of the unit's oxidation catalyst in accordance with EPA Reference Method 10. Inlet concentrations of CO will be determined in units of parts per million, dry volume (ppmvd). Corresponding inlet and outlet CO concentrations will be used to compute catalyst destruction efficiency for comparison to applicable emission limits.

At each 2SLB RICE, three 60-minute test runs will be performed while the unit is operating at no less than 90% site-rating. Relevant engine parameters will be recorded and submitted with the test results. Kerr McGee will submit a detailed testing protocol for Division approval at least 30 days prior to each engine test. The results of each engine test will be submitted for Division approval no more than 60 days after completion of the test.

Stack Gas Flow Rates (Engine Catalyst Outlets)

Stack gas flow rates will be determined in accordance with EPA Methods 1, 2, 3A and 4. Concurrent with each 60-minute pollutant emission test at each engine outlet, stack gas velocity will be measured in accordance with EPA Method 2 at points conforming to EPA Method 1. Stack gas velocity data will be combined with concurrent stack gas diluent and moisture concentration data to calculate stack gas volumetric flow rates for each 60-minute test period in units of dry standard cubic feet per minute (dscfm). All quality assurance procedures required by the applicable Reference Methods must be strictly followed.

Stack Gas Moisture Content (Engine Catalyst Outlets)

Stack gas moisture content will be determined in accordance with EPA Method 4. Each Method 4 testing period will consist of withdrawing a sample of stack gas at a constant flow rate through a stainless steel sample probe and Teflon sample line. The sample will pass through a series of four chilled glass impingers and through a calibrated dry gas meter. Prior to sampling, the first two impingers will be seeded with 100 milliliters of water. The third impinger will be empty, and the fourth impinger will be seeded with 250 grams of dried silica gel. Following each 60-minute sampling period, the moisture gain in the impingers will be measured gravimetrically to determine the moisture content of the stack gas. Stack gas moisture content will be determined in units of wet volume percent (%vw).

Oxygen, Carbon Dioxide, Nitrogen Oxides and Carbon Monoxide (Engine Catalyst Outlets)

Oxygen and carbon dioxide emissions will be determined in accordance with EPA Method 3A. Nitrogen oxide emissions will be determined in accordance with EPA Method 7E. Carbon monoxide emissions will be determined in accordance with EPA Method 10. Each Method 3A, 7E and 10 testing period will consist of withdrawing a sample of stack gas at a constant flow rate though a stainless steel sample probe and a heated Teflon sample line. The sample will be conditioned as necessary to remove moisture and directed to a paramagnetic oxygen analyzer, a non-dispersive infrared carbon dioxide analyzer, a chemiluminescent nitrogen oxides analyzer, and a gas filter correlation infrared carbon monoxide analyzer. Emission concentrations of O_2 and CO_2 will be determined in units of dry volume percent (%vd). Emission concentrations of NO_x and CO will be determined in units of parts per million, dry volume (ppmvd). Effluent gas concentration data will be electronically logged as (at minimum) one-minute averages, reduced to 60-minute averages and corrected for analyzer drift. All gaseous analyzers will be properly linearized prior to sampling; analyzer calibration bias will be recorded before and after each 60-minute test period in accordance with the applicable EPA Reference Methods. All quality assurance procedures required by the EPA Reference Methods (including, but not limited to, pollutant stratification tests and the NO_x analyzer converter efficiency test) must be strictly followed.

Carbon Monoxide (Engine Catalyst Inlets)

Concurrent with each catalyst outlet testing period, carbon monoxide concentrations at the catalyst inlet will be determined in accordance with EPA Method 10. Each sampling period will consist of withdrawing a sample of stack gas at a constant flow rate though a stainless steel sample probe and a heated Teflon sample line. The sample will be conditioned as necessary to remove moisture and directed to a gas filter correlation infrared carbon monoxide analyzer. Emission concentrations of CO will be determined in units of parts per million, dry volume (ppmvd). Pollutant gas concentration data will be electronically logged as (at minimum) one-minute averages, reduced to 60-minute averages and corrected for analyzer drift. All gaseous analyzers will be properly linearized prior to sampling; analyzer calibration bias will be recorded before and after each 60-minute test period in accordance with EPA Reference Method 10.

Formaldehyde (Engine Catalyst Outlets)

Concurrent with each 60-minute pollutant test period, formaldehyde emissions will be determined in accordance with either EPA Method 320 or 323. Formaldehyde concentrations will be determined in units of parts per million, wet volume (ppmvw). Wet volume HCHO concentrations will be combined with corresponding stack gas moisture content data to calculate HCHO concentrations in units of ppmvd. All quality assurance procedures required by the EPA Reference Method must be strictly followed.

Engine Operating Parameters

Three 60-minute runs will be performed on each 2SLB RICE at maximum ($\geq$ 90% site rating) operating load. Concurrent with each 60-minute test period, the following engine operating parameters will be recorded:

- Engine load (HP)
- Engine fuel use (scf/hour)
- Catalyst inlet temperature (°F)
- Catalyst pressure drop ("H_2O)

Data Reduction

1. Following sampling, average NO_x, CO and HCHO concentrations in units of pounds per standard cubic foot (lb/scf), dry basis, will be computed as follows:

$$C_d = C_{ppmvd} * CF$$

Where: C_d is the 60-minute average pollutant (i.e., NO_x, CO or HCHO) concentration in units of pounds per standard cubic foot, dry basis,

C_{ppmvd} is the drift-corrected 60-minute average pollutant (i.e., NO_x, CO or HCHO) concentration in units of parts per million, dry volume, and

CF is a conversion factor equal to: 1.194×10^{-7} lb/ppmvd·scf for NO_x,

7.269×10^{-8} lb/ppmvd·scf for CO,
7.793×10^{-8} lb/ppmvd·scf for HCHO.

2. **Pollutant concentrations and stack gas volumetric flow rates will be used to determine average NO_x, CO and HCHO mass emission rates in units of pounds per hour, as follows:**

$$E_{\frac{lb}{hr}} = C_d \cdot Q_{dscfm} \cdot 60$$

Where: $E_{lb/hr}$ is the 60-minute average pollutant mass emission rate in units of pounds per hour,
C_d is the drift-corrected 60-minute average pollutant (i.e., NO_x, CO or HCHO) concentration in units of pounds per standard cubic foot, dry basis, and
Q_{dscfm} is the corresponding engine outlet volumetric flow rate in units of dry standard cubic foot per minute.

3. **Pollutant mass emission rates will be combined with engine fuel use and fuel heat content data to determine average NO_x, CO and HCHO emission rates in units of pounds per million British thermal units (lb/mmBtu).**

$$lb/mmBtu = \frac{E_{\frac{lb}{hr}} \cdot 10^6}{F_{fuel} \cdot HC_{fuel}}$$

Where: $E_{lb/hr}$ is the 60-minute average pollutant mass emission rate in units of pounds per hour,
F_{fuel} is the 60-minute total engine fuel consumption in units of standard cubic feet per hour (scfh), and
HC_{fuel} is the heat content of the fuel gas (as determined by a recent fuel gas analysis) in units of British thermal units per standard cubic foot.

4. **If engine fuel consumption data are unavailable for any test run, calculations will be performed in accordance with EPA Reference Method 19 to compute pollutant mass emission rates in units of lb/mmBtu using Equation 19-1 as shown below:**

$$lb/mmBtu = C_d F_d \left(\frac{20.9}{20.9 - O_2\%vd} \right)$$

Where: C_d is the drift-corrected 60-minute average pollutant (i.e., NO_x, CO or HCHO) concentration in units of pounds per standard cubic foot, dry basis,
F_d is equal to 8,710 dry standard cubic feet per million British thermal units (dscf/mmBtu), and
$O_2\%vd$ is the 60-minute average oxygen concentration in units of dry volume percent.

5. **Pollutant mass emission rates in units of pounds per hour will be converted to units of tons per year, as follows:**

$$E_{tpy} = E_{\frac{lb}{hr}} \cdot \frac{8{,}760}{2{,}000}$$

Where: $\mathbf{E_{lb/hr}}$ is the 60-minute average pollutant mass emission rate in units of pounds per hour,
8,760 is the maximum number or possible operating hours per year, and
2,000 is the number of pounds per ton.

6. **Corresponding inlet and outlet CO concentrations in units of ppmvd will be used to compute catalyst destruction efficiency using the following equation:**

$$\%DRE = 100 \cdot \left(1 - \left(\frac{C_{Outlet}}{C_{Inlet}} \right) \right)$$

Where: $\mathbf{C_{Outlet}}$ is the drift-corrected 60-minute average outlet CO concentration (ppmvd), and
$\mathbf{C_{Inlet}}$ is the drift-corrected 60-minute average inlet CO concentration (ppmvd).

APPENDIX E

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

EXISTING >500 HP RICE LOCATED AT MINOR SOURCES IN THE UINTA BASIN TO BE RETROFITTED WITH OXIDATION CATALYSTS

Overview and Purpose

Kerr-McGee has agreed to retrofit certain reciprocating internal combustion engines ("RICE") located at minor sources in the Uinta Basin with oxidation catalysts as part of a settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.D., Kerr-McGee will retrofit the following RICE with oxidation catalysts:

Compressor Station	Engine ID(s)	Engine	Hp (each)
Morgan State C.S.	ENG1	Caterpillar 3516 TALE	1340
South Central C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
South East C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
North C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
North East C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
South C.S.	ENG1	Caterpillar 3516 TALE	1340
East Junior C.S.	ENG1	Caterpillar 3516 TALE	1340
East C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
East Bench	ENG1 & 2	Caterpillar 3516 TALE	1340
Archie Bench C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
L16 C.S.	ENG1	Caterpillar 3412 TALE	637
Willow Creek C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
Sage Grouse C.S.	ENG1 & 2	Caterpillar 3516 TALE	1340
Flat Mesa 2-7 (a.k.a. Bonanza West)	ENG1	Caterpillar 3516 TALE	1340
Bonanza East	ENG1 & 2	Caterpillar 3516 TALE	1340

APPENDIX F

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

CARBON MONOXIDE CONTROL EFFICIENCY PORTABLE ANALYZER MONITORING PROTOCOL

Determination of Carbon Monoxide Control Efficiency from Controlled Natural Gas-Fired Reciprocating Engines Located in the Uinta Basin

TABLE OF CONTENTS

OVERVIEW AND PURPOSE

Kerr-McGee has agreed to conduct portable analyzer testing for carbon monoxide ("CO") on certain reciprocating internal combustion engines ("RICE") located in the Uinta Basin that are controlled with oxidation catalysts as part of a settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.D., Kerr-McGee will conduct portable analyzer testing on certain RICE located in the Uinta Basin that will be controlled with oxidation catalysts.

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This protocol was prepared to be implemented by Kerr-McGee Oil and Gas Onshore LP, Westport Field Services LLC and/or certain of their corporate affiliates ("Kerr-McGee") will monitor carbon monoxide (CO) and oxygen (O_2) concentrations from controlled natural gas-fired reciprocating engines using portable analyzers with electrochemical cells.

1.2 Principle. A gas sample is continuously extracted from a stack and conveyed to a portable analyzer for determination of CO and O_2 gas concentrations using electrochemical cells. Analyzer design specifications, performance specifications, and test procedures are provided to ensure reliable data. Additions to or modifications of vendor-supplied analyzers (e.g. heated sample line, flow meters, etc.) may be required to meet the design specifications of this test method.

2. RANGE AND SENSITIVITY

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

2.1.1 CO Span Gas. Choose a CO span gas such that the concentration is approximately 1.25 times average expected pre-catalyst stack gas reading.

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

2.1.2 NO Span Gas. The NO span gas shall be approximately 250 ppm.

3. DEFINITIONS

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

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

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

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

3.1.4 Data Recorder. It is recommended that the analyzers be equipped with a strip chart recorder, computer, or digital recorder for recording measurement data. However, the operator may record the test results manually in accordance with the requirements of Section 7.4.

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

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

3.4 Zero Calibration Error. For the CO channel, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas. For the O_2 channel, the difference, expressed as percent O_2, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas.

3.5 Span Calibration Error. For the CO channel, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas. For the O_2 channel, the difference, expressed as percent O_2, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas.

3.6 Response Time. The amount of time required for the measurement system to display 95 percent of a step change in the CO gas concentration on the data recorder.

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

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

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

3.10 Test. The collection of emissions data consisting of two consecutive 21 minute sampling periods, 21 minutes pre-catalyst and 21 minutes post catalyst, from each source.

4. MEASUREMENT SYSTEM PERFORMANCE SPECIFICATIONS

4.1 Zero Calibration Error. Less than or equal to ±3 percent of the span gas value for CO channels and less than or equal to ±0.3 percent O_2 for the O_2 channel.

4.2 Span Calibration Error. Less than or equal to ±5 percent of the span gas value for CO channels and less than or equal to ±0.5 percent O_2 for the O_2 channel.

4.3 Linearity. For the zero, mid-level, and span gases, the absolute value of the difference, expressed as a percent of the span gas, between the gas value and the analyzer response shall not be greater than 2.5 percent for the CO cell.

4.4 Stability Check Response. The analyzer responses to CO span gases shall not vary more than 3.0 percent of span gas value over a 30-minute period or more than 2.0 percent of the span gas value over a 15-minute period.

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

5. APPARATUS AND REAGENTS

5.1 Measurement System. Use any measurement system that meets the performance and design specifications in Sections 4 and 5 of this method. The sampling system shall maintain the gas sample at a temperature above the dew point up to the moisture removal system. The sample conditioning system shall be designed so there are no entrained water droplets in the gas sample when it contacts the electrochemical cells. A schematic of an acceptable measurement system is shown in Figure 1. The essential components of the measurement system are described below:

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

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

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

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

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

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

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

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

5.1.9 Gas Analyzer. A device containing electrochemical cells to determine the CO and O_2 concentrations in the sample gas stream. The analyzer shall meet the applicable performance specifications of Section 4. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate (e.g., precision rotameter, pressure gauge downstream of all flow controls, etc.) shall be provided at the analyzer.

5.1.10 Data Recorder. A strip chart recorder, computer, or digital recorder, for recording measurement data. The data recorder resolution (i.e., readability) shall be at least 1 ppm for CO and 0.1 percent O_2 for O_2; and one degree (C or F) for temperature.

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

5.2 Calibration Gases. Both the CO and NO calibration gases for the gas analyzer shall be CO or

NO in nitrogen.

5.2.1 Span Gases. Used for calibration error, linearity, and interference checks of each nominal range of each cell. Select concentrations according to procedures in Section 2.1.1. Clean dry air may be used as the span gas for the O_2 cell as specified in Section 2.1.2.

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

5.2.3 Zero Gas. Concentration of less than 0.25 percent of the span gas for each component. Ambient air may be used in a well ventilated area for the CO.

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

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

6.2 Linearity Check. Conduct the following procedure once for each nominal range to be used on each electrochemical cell. After a linearity check is completed, it remains valid for seven consecutive calendar days. After the seven calendar day period has elapsed, the linearity check must be reaccomplished. Additionally, reaccomplish the linearity check if the cell is replaced.

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

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

6.3 Stability Check. Conduct the following procedure once for the maximum nominal range to be used on each electrochemical cell. After a stability check is completed, it remains valid for seven consecutive calendar days. After the seven calendar day period has elapsed, the stability check must be reaccomplished. Additionally, reaccomplish the stability check if the CO cell is replaced.

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

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

6.4 Interference Check. Conduct the following procedure once for the average anticipated NO stack gas concentration as reported by the manufacuture (250 ppm for Caterpillar lean burns). After a interference check is completed, this value will be utilized for interference calculations for the next 7 calendar days. After the seven calendar day period has elapsed, the interference check must be reaccomplished.

6.4.1 Interference Check Procedure. Inject the 250 ppm NO span gas for the into the analyzer and record the analyzer response at least once per minute until the conclusion of the interference check. One-minute average values may be used instead of instantaneous readings. After the analyzer response has stabilized, continue to flow the span gas for at least a 15-minute period. Make no adjustments to the analyzer during the stability check except to maintain constant flow. Record the CO cell response to this NO calibration gas.

7. EMISSION TEST PROCEDURES.

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

7.1. Pre/Post-Catalyst Sampling. Select both a pre-catalyst and post catalyst sampling site that will provide continuous uninterrupted exhaust gas flow.

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

7.3 Pretest Calibration Error Check. Conduct a zero and span calibration error check before testing each new facility. Conduct the calibration error check near the sampling location just prior to the start of the first emissions test.

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

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

7.3.3 Response Time Determination. Determine the CO response time by observing the time required to respond to 95 percent of a step change in the analyzer response for both the zero and span gases. Note the longer of the two times as the response time.

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

7.4 Sample Collection. Position the sampling probe at the pre-catalyst sample point and begin sampling at the same rate used during the calibration error check. Maintain constant rate sampling (± 10 percent of the analyzer flow rate value used in Section 7.3.2) during the entire test. The concentration data must be recorded either (1) at least once each minute, or (2) as a block average for the test using values sampled at least once each minute. Repeat this procedure from the post-catalyst sampling location. Two consecutive 21 minute samples, one pre-catalyst and one post catalyst, shall be considered a test for each source

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

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

8.1 Linearity Check Data. Using Form A, record the analyzer responses in ppm for CO, and percent O_2 for the zero, mid-level, and span gases injected during the linearity check under Section 6.2.2.

8.2 Stability Check Data. Record the analyzer response in pmm for CO at least once per minute during the stability check under Section 6.3.1. One-minute average values may be used instead of instantaneous readings. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. If the concentration reaches a peak value within five minutes of the gas injection, you may choose to record the data for at least a 15-minute stability check period following the peak. Use the information recorded to determine the analyzer stability under Section 6.3.2.

8.3 Pretest Calibration Error Check Data. On Form C, record the analyzer responses to the zero and span gases for CO and O_2 injected prior to testing each new source. Record the calibration zero and span gas concentrations for CO and O_2. For CO, record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. For O_2, record the absolute value of the difference between the analyzer response and the O_2 calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer O_2 response, as applicable, with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. Record the response times for the CO zero and span gases as described under Section 7.3.3. Select the longer of the two times as the response time for that pollutant.

8.4 Test Data. On Form D-1 record the source operating parameters during the test. Record the test start and end times. From the analyzer responses recorded each minute during the test, obtain the average flue gas concentration of each pollutant.

9. CONTROL EFFICIENCY CALCULATIONS

9.1 Control Efficiency Calculations. CO control efficiencies will be calculated using the following calculation:

$$\% \quad Control = \frac{(C_{pre} - C_{post})}{C_{pre}} \times 100$$

where: % control = actual control efficiency of the oxidation catalyst

C_{Pre} = stack gas concentration at the pre-catalyst sampling location (ppm)

C_{post} = stack gas concentration at the post-catalyst sampling location (ppm)

9.2 Interference Check. Utilize the data collected in Section 6.3.4 and the average pre-catalyst CO emission concentrations to calculate interference responses (I_{CO}) for the CO cell. If an interference response exceeds 5 percent, all emission test results since the last successful interference test for that compound are invalid.

9.2.1 CO Interference Calculation.

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

where:

I_{CO} = CO interference response (percent)

$R_{CO\text{-}NO}$ = CO response to NO span gas (ppm CO)

C_{NOG} = concentration of NO span gas (ppm NO)

C_{NOS} = Anticipated concentration of NO in stack gas (250 ppm NO)

C_{COS} = concentration of CO in stack gas (ppm CO)

10. REPORTING REQUIREMENTS AND RECORD KEEPING REQUIREMENTS

Test reports shall be submitted to the Environmental Protection Agency (EPA), as required by Section IV C of Consent Decree, within thirty (30) days of completing the test. A separate test report shall be submitted for each facility where an emission source was tested and, at a minimum, the following information shall be included:

- **Form A, Linearity/Interference Check Data Sheet,** Submit the linearity check as required by Section 6.2 for the nominal range tested.
- **Form B, Stability Check Data Sheet,** Submit the stability check as required by Section 6.4 for the nominal range tested.
- **Form C, Calibration Error Check Data Sheet**
- **Form D-1,** Submit the appropriate test results form.

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

Form A

Linearity/Interference Check Data Sheet

Date:______________

Analyst:__________________________________

Analyzer Manufacturer/Model #:____

Analyzer Serial #:_______________________________________

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

Form B
Stability Check Data Sheet

Date:______________ Analyst:____

Analyzer Manufacturer/Model #:____

Analyzer Serial #:____

Pollutant: CO Span Gas Concentration (ppm):______________

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

For 30-minute Stability Check Period:

Maximum Concentration (ppm): ___________ Minimum Concentration (ppm): ___________

For 15-minute Stability Check Period:

Maximum Concentration (ppm): ___________ Minimum Concentration (ppm): ___________

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

Stability Time (minutes): ___________

Form C
Calibration Error Check Data Sheet

Company:____________________ **Facility:**____________________

Source Tested:____________________ **Date:**____________________

Analyst:____________________ **Analyzer Serial #:**____________________

Analyzer Manufacturer/Model #:____________________

PRETEST CALIBRATION ERROR CHECK								
			A	B	|A-B|	|A-B|/SG*100		
		Pump Flow Rate (Indicate Units)	Analyzer Reading (Indicate Units)	Calibration Gas Concentration (Indicate Units)	Absolute Difference (Indicate Units)	Percent of Span Note 1	Calibration Valid (Yes or No)	Response Time (Minutes)
CO	Zero							
	Span							
O_2	Zero							
	Span							

SG = Span Gas

Form D-1
Reciprocating Engine Test Results

Company:______________________________ Facility:______________________________

Source Tested:__________________________ Date:________________________________

Source Manufacturer/Model #:____

Site-rated Horsepower:__________________ Source Serial #:_________________________

Type of Emission Control:____

Analyst:_______________________________ Analyzer Serial #:_______________________

Analyzer Manufacturer/Model #:____

Operating Conditions

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

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

[1] As reported by the Manufacturer

Test Results

Test Start Time:_____________ ______Test End Time:_______________________________

O_2	CO				
Avg. Tested O_2 %	Avg. Pre-Catalyst CO ppm	Avg. Post-Catalyst CO ppm	Tested CO Reduction (%)	Required CO Reduction (%)	CO Interference Response (I_{CO}, %):
				93%	

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

________________________________ ________________________________

Print Name Signature

APPENDIX G

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

HIGH-BLEED PNEUMATIC CONTROLLERS IN THE UINTA BASIN TO BE RETROFITTED WITH LOW-BLEED PNEUMATIC CONTROLLERS

Overview and Purpose

Kerr-McGee has agreed to retrofit certain high-bleed Pneumatic Controllers in the Uinta Basin as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.E., Kerr-McGee will retrofit the following high-bleed Pneumatic Controllers with low-bleed Pneumatic Controllers:

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	Bonanza Fed. 3-15	1
Cemco	Liquid Level	Ankerpont 2-6 ETAL	2
Cemco	Liquid Level	Archee 01-202	2
Cemco	Liquid Level	Bayless State 2-1	2
Cemco	Liquid Level	Bitter Creek 1122-3D	2
Cemco	Liquid Level	Bitter Creek 1122-5A	2
Cemco	Liquid Level	Bitter Creek 1122-6I	2
Cemco	Liquid Level	Bitter Creek 4-2	2
Cemco	Liquid Level	Bitter Creek 9-2	2
Cemco	Liquid Level	Bonanza 04-06	2
Cemco	Liquid Level	Bonanza 06-02	2
Cemco	Liquid Level	Bonanza 08-02	2
Cemco	Liquid Level	Bonanza 08-03	2
Cemco	Liquid Level	Bonanza 09-05	2
Cemco	Liquid Level	Bonanza 09-06	2
Cemco	Liquid Level	Bonanza 10-02	2
Cemco	Liquid Level	Bonanza 1023-10L	2
Cemco	Liquid Level	Bonanza 1023-11K	2
Cemco	Liquid Level	Bonanza 1023-17B	2
Cemco	Liquid Level	Bonanza 1023-18B	2
Cemco	Liquid Level	Bonanza 1023-18DX	2
Cemco	Liquid Level	Bonanza 1023-18G	2
Cemco	Liquid Level	Bonanza 1023-1A	2
Cemco	Liquid Level	Bonanza 1023-1C	2
Cemco	Liquid Level	Bonanza 1023-1E	2
Cemco	Liquid Level	Bonanza 1023-1G	2
Cemco	Liquid Level	Bonanza 1023-2A	2
Cemco	Liquid Level	Bonanza 1023-2C	2
Cemco	Liquid Level	Bonanza 1023-2E	2
Cemco	Liquid Level	Bonanza 1023-2G	2
Cemco	Liquid Level	Bonanza 1023-2I	2
Cemco	Liquid Level	Bonanza 1023-2MX	2
Cemco	Liquid Level	Bonanza 1023-2O	2
Cemco	Liquid Level	Bonanza 1023-4A	2
Cemco	Liquid Level	Bonanza 1023-4C	2
Cemco	Liquid Level	Bonanza 1023-4E	2
Cemco	Liquid Level	Bonanza 1023-4G	2
Cemco	Liquid Level	Bonanza 1023-4M	2
Cemco	Liquid Level	Bonanza 1023-4O	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	Bonanza 1023-5AX	2
Cemco	Liquid Level	Bonanza 1023-5C	2
Cemco	Liquid Level	Bonanza 1023-5G	2
Cemco	Liquid Level	Bonanza 1023-5M	2
Cemco	Liquid Level	Bonanza 1023-5O	2
Cemco	Liquid Level	Bonanza 1023-6A	2
Cemco	Liquid Level	Bonanza 1023-6C	2
Cemco	Liquid Level	Bonanza 1023-6E	2
Cemco	Liquid Level	Bonanza 1023-6G	2
Cemco	Liquid Level	Bonanza 1023-6M	2
Cemco	Liquid Level	Bonanza 1023-6O	2
Cemco	Liquid Level	Bonanza 1023-7B	2
Cemco	Liquid Level	Bonanza 1023-7D	2
Cemco	Liquid Level	Bonanza 1023-7L	2
Cemco	Liquid Level	Bonanza 1023-7P	2
Cemco	Liquid Level	Bonanza 1023-8A	2
Cemco	Liquid Level	Bonanza 1023-8F	2
Cemco	Liquid Level	Bonanza 1023-8L	2
Cemco	Liquid Level	Bonanza 1023-8N	2
Cemco	Liquid Level	Bonanza 1023-9E	2
Cemco	Liquid Level	Bonanza 10-3	2
Cemco	Liquid Level	Bonanza 10-4	2
Cemco	Liquid Level	Bonanza 11-2	2
Cemco	Liquid Level	Bonanza1023-4I	2
Cemco	Liquid Level	CIGE 003	2
Cemco	Liquid Level	CIGE 004	2
Cemco	Liquid Level	CIGE 005	2
Cemco	Liquid Level	CIGE 006	2
Cemco	Liquid Level	CIGE 007	2
Cemco	Liquid Level	CIGE 008	2
Cemco	Liquid Level	CIGE 010	2
Cemco	Liquid Level	CIGE 013	2
Cemco	Liquid Level	CIGE 018	2
Cemco	Liquid Level	CIGE 019	2
Cemco	Liquid Level	CIGE 020	2
Cemco	Liquid Level	CIGE 022	2
Cemco	Liquid Level	CIGE 023	2
Cemco	Liquid Level	CIGE 024	2
Cemco	Liquid Level	CIGE 025	2
Cemco	Liquid Level	CIGE 027	2
Cemco	Liquid Level	CIGE 028	2
Cemco	Liquid Level	CIGE 030	2
Cemco	Liquid Level	CIGE 031	2
Cemco	Liquid Level	CIGE 034	2
Cemco	Liquid Level	CIGE 036D	2
Cemco	Liquid Level	CIGE 037D	2
Cemco	Liquid Level	CIGE 038	2
Cemco	Liquid Level	CIGE 040	2
Cemco	Liquid Level	CIGE 042	2
Cemco	Liquid Level	CIGE 043	2
Cemco	Liquid Level	CIGE 044	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CIGE 045	2
Cemco	Liquid Level	CIGE 046	2
Cemco	Liquid Level	CIGE 047	2
Cemco	Liquid Level	CIGE 048	2
Cemco	Liquid Level	CIGE 051D	2
Cemco	Liquid Level	CIGE 052	2
Cemco	Liquid Level	CIGE 054	2
Cemco	Liquid Level	CIGE 055	2
Cemco	Liquid Level	CIGE 056	2
Cemco	Liquid Level	CIGE 057	2
Cemco	Liquid Level	CIGE 060	2
Cemco	Liquid Level	CIGE 061	2
Cemco	Liquid Level	CIGE 062D	2
Cemco	Liquid Level	CIGE 063D	2
Cemco	Liquid Level	CIGE 064D	2
Cemco	Liquid Level	CIGE 067A	2
Cemco	Liquid Level	CIGE 068D	2
Cemco	Liquid Level	CIGE 070	2
Cemco	Liquid Level	CIGE 071	2
Cemco	Liquid Level	CIGE 072	2
Cemco	Liquid Level	CIGE 075	2
Cemco	Liquid Level	CIGE 076D	2
Cemco	Liquid Level	CIGE 077D	2
Cemco	Liquid Level	CIGE 078	2
Cemco	Liquid Level	CIGE 079D	2
Cemco	Liquid Level	CIGE 080D	2
Cemco	Liquid Level	CIGE 086	2
Cemco	Liquid Level	CIGE 087D	2
Cemco	Liquid Level	CIGE 088D	2
Cemco	Liquid Level	CIGE 089D	2
Cemco	Liquid Level	CIGE 090D	2
Cemco	Liquid Level	CIGE 091D	2
Cemco	Liquid Level	CIGE 092	2
Cemco	Liquid Level	CIGE 093D	2
Cemco	Liquid Level	CIGE 094D	2
Cemco	Liquid Level	CIGE 095D	2
Cemco	Liquid Level	CIGE 096D	2
Cemco	Liquid Level	CIGE 098	2
Cemco	Liquid Level	CIGE 099D	2
Cemco	Liquid Level	CIGE 100D	2
Cemco	Liquid Level	CIGE 101D	2
Cemco	Liquid Level	CIGE 102	2
Cemco	Liquid Level	CIGE 103D	2
Cemco	Liquid Level	CIGE 105D	2
Cemco	Liquid Level	CIGE 106D	2
Cemco	Liquid Level	CIGE 107D	2
Cemco	Liquid Level	CIGE 108D	2
Cemco	Liquid Level	CIGE 109D	2
Cemco	Liquid Level	CIGE 110	2
Cemco	Liquid Level	CIGE 111D	2
Cemco	Liquid Level	CIGE 113	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CIGE 115	2
Cemco	Liquid Level	CIGE 116	2
Cemco	Liquid Level	CIGE 117	2
Cemco	Liquid Level	CIGE 118	2
Cemco	Liquid Level	CIGE 119	2
Cemco	Liquid Level	CIGE 120	2
Cemco	Liquid Level	CIGE 121	2
Cemco	Liquid Level	CIGE 122	2
Cemco	Liquid Level	CIGE 123	2
Cemco	Liquid Level	CIGE 124	2
Cemco	Liquid Level	CIGE 125	2
Cemco	Liquid Level	CIGE 127	2
Cemco	Liquid Level	CIGE 129	2
Cemco	Liquid Level	CIGE 130	2
Cemco	Liquid Level	CIGE 131	2
Cemco	Liquid Level	CIGE 133	2
Cemco	Liquid Level	CIGE 134	2
Cemco	Liquid Level	CIGE 135	2
Cemco	Liquid Level	CIGE 137	2
Cemco	Liquid Level	CIGE 138A	2
Cemco	Liquid Level	CIGE 139	2
Cemco	Liquid Level	CIGE 140	2
Cemco	Liquid Level	CIGE 142	2
Cemco	Liquid Level	CIGE 143	2
Cemco	Liquid Level	CIGE 144	2
Cemco	Liquid Level	CIGE 145	2
Cemco	Liquid Level	CIGE 146	2
Cemco	Liquid Level	CIGE 148	2
Cemco	Liquid Level	CIGE 149	2
Cemco	Liquid Level	CIGE 150	2
Cemco	Liquid Level	CIGE 151	2
Cemco	Liquid Level	CIGE 152	2
Cemco	Liquid Level	CIGE 153	2
Cemco	Liquid Level	CIGE 154	2
Cemco	Liquid Level	CIGE 155	2
Cemco	Liquid Level	CIGE 156	2
Cemco	Liquid Level	CIGE 157	2
Cemco	Liquid Level	CIGE 158	2
Cemco	Liquid Level	CIGE 159	2
Cemco	Liquid Level	CIGE 161	2
Cemco	Liquid Level	CIGE 162	2
Cemco	Liquid Level	CIGE 163	2
Cemco	Liquid Level	CIGE 164	2
Cemco	Liquid Level	CIGE 165	2
Cemco	Liquid Level	CIGE 166	2
Cemco	Liquid Level	CIGE 167	2
Cemco	Liquid Level	CIGE 168	2
Cemco	Liquid Level	CIGE 170	2
Cemco	Liquid Level	CIGE 171	2
Cemco	Liquid Level	CIGE 172	2
Cemco	Liquid Level	CIGE 173	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CIGE 174	2
Cemco	Liquid Level	CIGE 177	2
Cemco	Liquid Level	CIGE 179	2
Cemco	Liquid Level	CIGE 180	2
Cemco	Liquid Level	CIGE 182	2
Cemco	Liquid Level	CIGE 183	2
Cemco	Liquid Level	CIGE 186	2
Cemco	Liquid Level	CIGE 187	2
Cemco	Liquid Level	CIGE 189	2
Cemco	Liquid Level	CIGE 190	2
Cemco	Liquid Level	CIGE 193	2
Cemco	Liquid Level	CIGE 194	2
Cemco	Liquid Level	CIGE 195	2
Cemco	Liquid Level	CIGE 196	2
Cemco	Liquid Level	CIGE 197	2
Cemco	Liquid Level	CIGE 198	2
Cemco	Liquid Level	CIGE 200	2
Cemco	Liquid Level	CIGE 201	2
Cemco	Liquid Level	CIGE 202	2
Cemco	Liquid Level	CIGE 203	1
Cemco	Liquid Level	CIGE 204	2
Cemco	Liquid Level	CIGE 205	2
Cemco	Liquid Level	CIGE 206	2
Cemco	Liquid Level	CIGE 207	2
Cemco	Liquid Level	CIGE 208	2
Cemco	Liquid Level	CIGE 209	2
Cemco	Liquid Level	CIGE 210	2
Cemco	Liquid Level	CIGE 212	2
Cemco	Liquid Level	CIGE 213	2
Cemco	Liquid Level	CIGE 214	2
Cemco	Liquid Level	CIGE 215X	1
Cemco	Liquid Level	CIGE 216	2
Cemco	Liquid Level	CIGE 217	2
Cemco	Liquid Level	CIGE 218	2
Cemco	Liquid Level	CIGE 219	2
Cemco	Liquid Level	CIGE 220	2
Cemco	Liquid Level	CIGE 221	2
Cemco	Liquid Level	CIGE 222	2
Cemco	Liquid Level	CIGE 223	2
Cemco	Liquid Level	CIGE 224	1
Cemco	Liquid Level	CIGE 225	2
Cemco	Liquid Level	CIGE 226	2
Cemco	Liquid Level	CIGE 227	2
Cemco	Liquid Level	CIGE 228	2
Cemco	Liquid Level	CIGE 229	2
Cemco	Liquid Level	CIGE 230	2
Cemco	Liquid Level	CIGE 231	2
Cemco	Liquid Level	CIGE 233	1
Cemco	Liquid Level	CIGE 234	2
Cemco	Liquid Level	CIGE 235	2
Cemco	Liquid Level	CIGE 236	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CIGE 237	1
Cemco	Liquid Level	CIGE 239	2
Cemco	Liquid Level	CIGE 240	2
Cemco	Liquid Level	CIGE 241	2
Cemco	Liquid Level	CIGE 244	2
Cemco	Liquid Level	CIGE 245	2
Cemco	Liquid Level	CIGE 247	2
Cemco	Liquid Level	CIGE 248	2
Cemco	Liquid Level	CIGE 249	2
Cemco	Liquid Level	CIGE 250	2
Cemco	Liquid Level	CIGE 251	2
Cemco	Liquid Level	CIGE 252	1
Cemco	Liquid Level	CIGE 253	1
Cemco	Liquid Level	CIGE 254	1
Cemco	Liquid Level	CIGE 255	2
Cemco	Liquid Level	CIGE 257	2
Cemco	Liquid Level	CIGE 258	2
Cemco	Liquid Level	CIGE 259	2
Cemco	Liquid Level	CIGE 260	2
Cemco	Liquid Level	CIGE 261	1
Cemco	Liquid Level	CIGE 262	2
Cemco	Liquid Level	CIGE 263	2
Cemco	Liquid Level	CIGE 265	2
Cemco	Liquid Level	CIGE 266	2
Cemco	Liquid Level	CIGE 268	2
Cemco	Liquid Level	CIGE 271	2
Cemco	Liquid Level	CIGE 274	2
Cemco	Liquid Level	CIGE 276	2
Cemco	Liquid Level	CIGE 277	2
Cemco	Liquid Level	CIGE 278	1
Cemco	Liquid Level	CIGE 279	1
Cemco	Liquid Level	CIGE 280	2
Cemco	Liquid Level	CIGE 281	2
Cemco	Liquid Level	CIGE 283	2
Cemco	Liquid Level	CIGE 284	2
Cemco	Liquid Level	CIGE 285	2
Cemco	Liquid Level	CIGE 286	2
Cemco	Liquid Level	CIGE 287	2
Cemco	Liquid Level	CIGE 288	2
Cemco	Liquid Level	CIGE 290	2
Cemco	Liquid Level	CIGE 291	2
Cemco	Liquid Level	CIGE 292	2
Cemco	Liquid Level	CIGE 293	2
Cemco	Liquid Level	CIGE 294	2
Cemco	Liquid Level	CIGE 295	2
Cemco	Liquid Level	CIGE 296	2
Cemco	Liquid Level	CIGE 297	2
Cemco	Liquid Level	CIGE 299	2
Cemco	Liquid Level	CIGE O97D	2
Cemco	Liquid Level	COG 002	2
Cemco	Liquid Level	COG 006	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	COG 011	2
Cemco	Liquid Level	CTB E 30S CA1	2
Cemco	Liquid Level	CTB E 31N CA1	2
Cemco	Liquid Level	CTB E 31N CA2	2
Cemco	Liquid Level	CTB E 34S CA1	2
Cemco	Liquid Level	CTB E 34S CA2	2
Cemco	Liquid Level	CTB E 35N CA1	2
Cemco	Liquid Level	CTB E 35S CA1	2
Cemco	Liquid Level	CTB E 35S CA2	2
Cemco	Liquid Level	CTB E 36S CA1	2
Cemco	Liquid Level	CTB E 36S CA2	2
Cemco	Liquid Level	CTB E 36S CA3	2
Cemco	Liquid Level	CTB E 6N CA1	2
Cemco	Liquid Level	CTB E 6N CA2	2
Cemco	Liquid Level	CTB W 1S CA1	2
Cemco	Liquid Level	CTB W 1S CA2	2
Cemco	Liquid Level	CTB W 31N CA1	2
Cemco	Liquid Level	CTB W 31N CA2	2
Cemco	Liquid Level	CTB W 31N CA3	2
Cemco	Liquid Level	CTB W 31N CA4	2
Cemco	Liquid Level	CTB W 32SE CA1	2
Cemco	Liquid Level	CTB W 32SE CA2	2
Cemco	Liquid Level	CTB W 32SE CA2	2
Cemco	Liquid Level	CTB W 32SE CA3	2
Cemco	Liquid Level	CTB W 32SE CA3	2
Cemco	Liquid Level	CTB W 32SE CA4	2
Cemco	Liquid Level	CTB W 32SE CA4	2
Cemco	Liquid Level	CTB W 33S CA1	2
Cemco	Liquid Level	CTB W 33S CA2	2
Cemco	Liquid Level	CTB W 33S CA3	2
Cemco	Liquid Level	CTB W 34N CA1	2
Cemco	Liquid Level	CTB W 34N CA2	2
Cemco	Liquid Level	CTB W 34N CA3	2
Cemco	Liquid Level	CTB W 34N CA4	2
Cemco	Liquid Level	CTB W 34N CA5	2
Cemco	Liquid Level	CTB W 34N CA6	2
Cemco	Liquid Level	CTB W 35N CA1	2
Cemco	Liquid Level	CTB W 35N CA2	2
Cemco	Liquid Level	CTB W 36S CA1	2
Cemco	Liquid Level	CTB W 36S CA2	2
Cemco	Liquid Level	CTB W 36S CA3	2
Cemco	Liquid Level	CTB W 4S CA2	2
Cemco	Liquid Level	CTB W 5S	2
Cemco	Liquid Level	CTB W 6S CA1	2
Cemco	Liquid Level	CTB W 6S CA2	2
Cemco	Liquid Level	CTB W4S CA1	2
Cemco	Liquid Level	Diablo 924-31M	2
Cemco	Liquid Level	Duncan Fed. 33-9	2
Cemco	Liquid Level	Fed. 33-177	2
Cemco	Liquid Level	Fed. 33-92	2
Cemco	Liquid Level	Fed. 35-5	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	FEDERAL 1022-15F	2
Cemco	Liquid Level	FEDERAL 1022-15J	2
Cemco	Liquid Level	FEDERAL 1022-28L	2
Cemco	Liquid Level	FEDERAL 1022-28M	2
Cemco	Liquid Level	Federal 1022-28N	2
Cemco	Liquid Level	Federal 1022-28O	2
Cemco	Liquid Level	FEDERAL 1022-29B	2
Cemco	Liquid Level	Federal 1022-29D	2
Cemco	Liquid Level	Federal 1022-29F	2
Cemco	Liquid Level	FEDERAL 1022-29H	2
Cemco	Liquid Level	FEDERAL 1022-29I	2
Cemco	Liquid Level	Federal 1022-31C	2
Cemco	Liquid Level	Federal 1022-31D	2
Cemco	Liquid Level	Federal 1022-31F	2
Cemco	Liquid Level	Federal 1022-31G	2
Cemco	Liquid Level	Federal 1022-31I	2
Cemco	Liquid Level	Federal 1022-31J	2
Cemco	Liquid Level	Federal 1022-33E	2
Cemco	Liquid Level	Federal 1022-33O	2
Cemco	Liquid Level	Federal 24-22	2
Cemco	Liquid Level	Federal 29-10-22	2
Cemco	Liquid Level	Federal 31-10-22	2
Cemco	Liquid Level	FEDERAL 920-25A	2
Cemco	Liquid Level	Flat Mesa 2-7	1
Cemco	Liquid Level	Glen Bench 822-27M	2
Cemco	Liquid Level	Glen Bench 12-36	2
Cemco	Liquid Level	Glen Bench 21-2	2
Cemco	Liquid Level	Glen Bench 22-2	2
Cemco	Liquid Level	Glen Bench 22-3	2
Cemco	Liquid Level	Glen Bench 23-21	2
Cemco	Liquid Level	Glen Bench 34-27	2
Cemco	Liquid Level	Glen Bench 822-21I	2
Cemco	Liquid Level	Glen Bench 822-22D	2
Cemco	Liquid Level	Glen Bench 822-22I	2
Cemco	Liquid Level	Glen Bench 822-22K	2
Cemco	Liquid Level	Glen Bench 822-22M	2
Cemco	Liquid Level	Glen Bench 822-27A	2
Cemco	Liquid Level	Glen Bench 822-27B	2
Cemco	Liquid Level	Glen Bench 822-27D	2
Cemco	Liquid Level	Glen Bench 822-27F	2
Cemco	Liquid Level	Glen Bench 822-27G	2
Cemco	Liquid Level	Glen Bench 822-27H	2
Cemco	Liquid Level	Glen Bench 822-27I	2
Cemco	Liquid Level	Glen Bench 822-27J	2
Cemco	Liquid Level	Glen Bench 822-27K	2
Cemco	Liquid Level	Glen Bench 822-27L	2
Cemco	Liquid Level	Glen Bench 822-27N	2
Cemco	Liquid Level	Glen Bench 822-27P	2
Cemco	Liquid Level	Hall Etal 31-18	2
Cemco	Liquid Level	Kennedy Wash 03-01	2
Cemco	Liquid Level	Kennedy Wash 11-1	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	Kennedy Wash 13-1	2
Cemco	Liquid Level	lizzard 1122-21O	2
Cemco	Liquid Level	Lizzard Creek Fed. 1-10	2
Cemco	Liquid Level	Lookout Point 1-16	1
Cemco	Liquid Level	LOVE 1121-10G	2
Cemco	Liquid Level	LOVE 1121-11K	2
Cemco	Liquid Level	LOVE 1121-14F	2
Cemco	Liquid Level	LOVE 1121-16A	2
Cemco	Liquid Level	Love 1121-16D	2
Cemco	Liquid Level	LOVE 1121-2M	2
Cemco	Liquid Level	LOVE 1121-7H	2
Cemco	Liquid Level	LOVE 1121-7N	2
Cemco	Liquid Level	LOVE 1121-8H	2
Cemco	Liquid Level	LOVE 1121-8N	2
Cemco	Liquid Level	Love Unit 1-11	2
Cemco	Liquid Level	Love Unit 1-12	2
Cemco	Liquid Level	Love Unit 4-1	2
Cemco	Liquid Level	Love Unit A1-18	2
Cemco	Liquid Level	McCook 1-142	2
Cemco	Liquid Level	Morgan St. 01-36	2
Cemco	Liquid Level	Morgan St. 02-36	2
Cemco	Liquid Level	Morgan St. 03-36	2
Cemco	Liquid Level	Morgan St. 04-36	2
Cemco	Liquid Level	Morgan St. 05-36	2
Cemco	Liquid Level	Morgan St. 06-36	2
Cemco	Liquid Level	Morgan St. 07-36	2
Cemco	Liquid Level	Morgan St. 08-36	2
Cemco	Liquid Level	Morgan St. 09-36	2
Cemco	Liquid Level	Morgan St. 10-36	2
Cemco	Liquid Level	Morgan St. 11-36	2
Cemco	Liquid Level	Morgan St. 12-36	2
Cemco	Liquid Level	Morgan St. 13-36	2
Cemco	Liquid Level	Morgan St. 14-36	2
Cemco	Liquid Level	Morgan St. 15-36	2
Cemco	Liquid Level	Morgan St. 16-36	2
Cemco	Liquid Level	Mulligan 8-1	2
Cemco	Liquid Level	Mulligan 822-24G	2
Cemco	Liquid Level	Mulligan Fed 823-19P	2
Cemco	Liquid Level	NBU 004	2
Cemco	Liquid Level	NBU 006	2
Cemco	Liquid Level	NBU 012	2
Cemco	Liquid Level	NBU 015	2
Cemco	Liquid Level	NBU 020	2
Cemco	Liquid Level	NBU 023	2
Cemco	Liquid Level	NBU 024N2	2
Cemco	Liquid Level	NBU 026	2
Cemco	Liquid Level	NBU 031	2
Cemco	Liquid Level	NBU 032Y	2
Cemco	Liquid Level	NBU 035Y	2
Cemco	Liquid Level	NBU 036	2
Cemco	Liquid Level	NBU 037XP	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 038N2	2
Cemco	Liquid Level	NBU 039N	2
Cemco	Liquid Level	NBU 041J	2
Cemco	Liquid Level	NBU 042	2
Cemco	Liquid Level	NBU 045	2
Cemco	Liquid Level	NBU 046	2
Cemco	Liquid Level	NBU 048N3	2
Cemco	Liquid Level	NBU 049V	2
Cemco	Liquid Level	NBU 050N2	2
Cemco	Liquid Level	NBU 051J	2
Cemco	Liquid Level	NBU 052J	2
Cemco	Liquid Level	NBU 053	2
Cemco	Liquid Level	NBU 054	1
Cemco	Liquid Level	NBU 056N2	2
Cemco	Liquid Level	NBU 057	2
Cemco	Liquid Level	NBU 060	2
Cemco	Liquid Level	NBU 063N3	2
Cemco	Liquid Level	NBU 064N3	2
Cemco	Liquid Level	NBU 065N3	2
Cemco	Liquid Level	NBU 067A	2
Cemco	Liquid Level	NBU 068N2	2
Cemco	Liquid Level	NBU 069N2	2
Cemco	Liquid Level	NBU 072N3	2
Cemco	Liquid Level	NBU 074N3	2
Cemco	Liquid Level	NBU 078	2
Cemco	Liquid Level	NBU 080V	2
Cemco	Liquid Level	NBU 081V	2
Cemco	Liquid Level	NBU 083J	2
Cemco	Liquid Level	NBU 085J	2
Cemco	Liquid Level	NBU 086J	2
Cemco	Liquid Level	NBU 088V	2
Cemco	Liquid Level	NBU 093	2
Cemco	Liquid Level	NBU 097	2
Cemco	Liquid Level	NBU 099	2
Cemco	Liquid Level	NBU 101	2
Cemco	Liquid Level	NBU 102	2
Cemco	Liquid Level	NBU 1020-12E	2
Cemco	Liquid Level	NBU 1020-13E	2
Cemco	Liquid Level	NBU 1020-24F	2
Cemco	Liquid Level	NBU 1021-10H	2
Cemco	Liquid Level	NBU 1021-11C	2
Cemco	Liquid Level	NBU 1021-15I	2
Cemco	Liquid Level	NBU 1021-16G	2
Cemco	Liquid Level	NBU 1021-1M	2
Cemco	Liquid Level	NBU 1021-22F	2
Cemco	Liquid Level	NBU 1021-23O	2
Cemco	Liquid Level	NBU 1021-2O	2
Cemco	Liquid Level	NBU 1022-11F	2
Cemco	Liquid Level	NBU 1022-11IX	2
Cemco	Liquid Level	NBU 1022-11J	2
Cemco	Liquid Level	NBU 1022-12P	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 1022-16A	2
Cemco	Liquid Level	NBU 1022-16B	2
Cemco	Liquid Level	NBU 1022-16C	2
Cemco	Liquid Level	NBU 1022-16D	2
Cemco	Liquid Level	NBU 1022-16E	2
Cemco	Liquid Level	NBU 1022-16M	2
Cemco	Liquid Level	NBU 1022-16O	2
Cemco	Liquid Level	NBU 1022-17I	2
Cemco	Liquid Level	NBU 1022-17K	2
Cemco	Liquid Level	NBU 1022-17M	2
Cemco	Liquid Level	NBU 1022-17O	2
Cemco	Liquid Level	NBU 1022-1A	2
Cemco	Liquid Level	NBU 1022-1B	2
Cemco	Liquid Level	NBU 1022-1F	2
Cemco	Liquid Level	NBU 1022-1G	2
Cemco	Liquid Level	NBU 1022-1H	2
Cemco	Liquid Level	NBU 1022-20C	2
Cemco	Liquid Level	NBU 1022-20E	2
Cemco	Liquid Level	NBU 1022-20I	2
Cemco	Liquid Level	NBU 1022-20K	2
Cemco	Liquid Level	NBU 1022-20M	2
Cemco	Liquid Level	NBU 1022-20O	2
Cemco	Liquid Level	NBU 1022-21C	2
Cemco	Liquid Level	NBU 1022-21I	2
Cemco	Liquid Level	NBU 1022-21N	2
Cemco	Liquid Level	NBU 1022-22F	2
Cemco	Liquid Level	NBU 1022-23F	2
Cemco	Liquid Level	NBU 1022-23K	2
Cemco	Liquid Level	NBU 1022-30A	2
Cemco	Liquid Level	NBU 1022-30D	2
Cemco	Liquid Level	NBU 1022-30E	2
Cemco	Liquid Level	NBU 1022-30H	2
Cemco	Liquid Level	NBU 1022-30K	2
Cemco	Liquid Level	NBU 1022-30L	2
Cemco	Liquid Level	NBU 1022-30O	2
Cemco	Liquid Level	NBU 1022-31B	2
Cemco	Liquid Level	NBU 1022-4B	2
Cemco	Liquid Level	NBU 1022-4K	2
Cemco	Liquid Level	NBU 1022-4M	2
Cemco	Liquid Level	NBU 1022-5C	2
Cemco	Liquid Level	NBU 1022-5G	2
Cemco	Liquid Level	NBU 1022-5K	2
Cemco	Liquid Level	NBU 1022-5N	2
Cemco	Liquid Level	NBU 1022-5P	2
Cemco	Liquid Level	NBU 1022-6A	2
Cemco	Liquid Level	NBU 1022-6I	2
Cemco	Liquid Level	NBU 1022-6M	2
Cemco	Liquid Level	NBU 1022-6O	2
Cemco	Liquid Level	NBU 1022-7C	2
Cemco	Liquid Level	NBU 1022-7D	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 1022-7E	2
Cemco	Liquid Level	NBU 1022-7F	2
Cemco	Liquid Level	NBU 1022-7G	2
Cemco	Liquid Level	NBU 1022-7P	2
Cemco	Liquid Level	NBU 1022-8A	2
Cemco	Liquid Level	NBU 1022-8E	2
Cemco	Liquid Level	NBU 1022-8K	2
Cemco	Liquid Level	NBU 1022-8L	2
Cemco	Liquid Level	NBU 1022-8M	2
Cemco	Liquid Level	NBU 1022-8N	2
Cemco	Liquid Level	NBU 1022-9C	2
Cemco	Liquid Level	NBU 1022-9E	2
Cemco	Liquid Level	NBU 1022-9M	2
Cemco	Liquid Level	NBU 1022-9O	2
Cemco	Liquid Level	NBU 103	2
Cemco	Liquid Level	NBU 104	2
Cemco	Liquid Level	NBU 105	2
Cemco	Liquid Level	NBU 106	2
Cemco	Liquid Level	NBU 107	2
Cemco	Liquid Level	NBU 108	2
Cemco	Liquid Level	NBU 109	2
Cemco	Liquid Level	NBU 110	2
Cemco	Liquid Level	NBU 111	2
Cemco	Liquid Level	NBU 112	2
Cemco	Liquid Level	NBU 113	2
Cemco	Liquid Level	NBU 115	2
Cemco	Liquid Level	NBU 116	2
Cemco	Liquid Level	NBU 117	2
Cemco	Liquid Level	NBU 118	2
Cemco	Liquid Level	NBU 119	2
Cemco	Liquid Level	NBU 120	2
Cemco	Liquid Level	NBU 121	2
Cemco	Liquid Level	NBU 122	2
Cemco	Liquid Level	NBU 123	2
Cemco	Liquid Level	NBU 124	2
Cemco	Liquid Level	NBU 125	2
Cemco	Liquid Level	NBU 126	2
Cemco	Liquid Level	NBU 127	2
Cemco	Liquid Level	NBU 128	2
Cemco	Liquid Level	NBU 129	2
Cemco	Liquid Level	NBU 130	2
Cemco	Liquid Level	NBU 131	2
Cemco	Liquid Level	NBU 132	2
Cemco	Liquid Level	NBU 133	2
Cemco	Liquid Level	NBU 134	2
Cemco	Liquid Level	NBU 136	2
Cemco	Liquid Level	NBU 137	2
Cemco	Liquid Level	NBU 138A	2
Cemco	Liquid Level	NBU 139	2
Cemco	Liquid Level	NBU 140	2
Cemco	Liquid Level	NBU 141	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 142	2
Cemco	Liquid Level	NBU 143	2
Cemco	Liquid Level	NBU 144	2
Cemco	Liquid Level	NBU 145	2
Cemco	Liquid Level	NBU 146	2
Cemco	Liquid Level	NBU 147	2
Cemco	Liquid Level	NBU 148	2
Cemco	Liquid Level	NBU 151	2
Cemco	Liquid Level	NBU 152	2
Cemco	Liquid Level	NBU 154	2
Cemco	Liquid Level	NBU 155	2
Cemco	Liquid Level	NBU 156	2
Cemco	Liquid Level	NBU 157	2
Cemco	Liquid Level	NBU 158	2
Cemco	Liquid Level	NBU 161	2
Cemco	Liquid Level	NBU 162	2
Cemco	Liquid Level	NBU 163	2
Cemco	Liquid Level	NBU 164	2
Cemco	Liquid Level	NBU 165	2
Cemco	Liquid Level	NBU 166	2
Cemco	Liquid Level	NBU 168	2
Cemco	Liquid Level	NBU 169	2
Cemco	Liquid Level	NBU 170	2
Cemco	Liquid Level	NBU 171	2
Cemco	Liquid Level	NBU 172	2
Cemco	Liquid Level	NBU 173	2
Cemco	Liquid Level	NBU 174	2
Cemco	Liquid Level	NBU 175	2
Cemco	Liquid Level	NBU 176	2
Cemco	Liquid Level	NBU 177	2
Cemco	Liquid Level	NBU 178	2
Cemco	Liquid Level	NBU 180	2
Cemco	Liquid Level	NBU 181	2
Cemco	Liquid Level	NBU 182	2
Cemco	Liquid Level	NBU 183	2
Cemco	Liquid Level	NBU 184	2
Cemco	Liquid Level	NBU 185	2
Cemco	Liquid Level	NBU 186	2
Cemco	Liquid Level	NBU 187	2
Cemco	Liquid Level	NBU 189	2
Cemco	Liquid Level	NBU 190	2
Cemco	Liquid Level	NBU 191	2
Cemco	Liquid Level	NBU 192	2
Cemco	Liquid Level	NBU 193	2
Cemco	Liquid Level	NBU 194	2
Cemco	Liquid Level	NBU 195	2
Cemco	Liquid Level	NBU 198	2
Cemco	Liquid Level	NBU 199	2
Cemco	Liquid Level	NBU 200	2
Cemco	Liquid Level	NBU 201	2
Cemco	Liquid Level	NBU 202	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 204	2
Cemco	Liquid Level	NBU 206	2
Cemco	Liquid Level	NBU 207	2
Cemco	Liquid Level	NBU 208	2
Cemco	Liquid Level	NBU 209	2
Cemco	Liquid Level	NBU 210	2
Cemco	Liquid Level	NBU 211	2
Cemco	Liquid Level	NBU 212	2
Cemco	Liquid Level	NBU 214	2
Cemco	Liquid Level	NBU 215	2
Cemco	Liquid Level	NBU 216	2
Cemco	Liquid Level	NBU 221X	2
Cemco	Liquid Level	NBU 222	2
Cemco	Liquid Level	NBU 223	2
Cemco	Liquid Level	NBU 224	2
Cemco	Liquid Level	NBU 228	2
Cemco	Liquid Level	NBU 229	2
Cemco	Liquid Level	NBU 230A	2
Cemco	Liquid Level	NBU 231	2
Cemco	Liquid Level	NBU 236	2
Cemco	Liquid Level	NBU 243	2
Cemco	Liquid Level	NBU 244	2
Cemco	Liquid Level	NBU 245	2
Cemco	Liquid Level	NBU 247	2
Cemco	Liquid Level	NBU 249	2
Cemco	Liquid Level	NBU 252	2
Cemco	Liquid Level	NBU 253	2
Cemco	Liquid Level	NBU 254	2
Cemco	Liquid Level	NBU 255	2
Cemco	Liquid Level	NBU 256	2
Cemco	Liquid Level	NBU 257	2
Cemco	Liquid Level	NBU 258	2
Cemco	Liquid Level	NBU 259	2
Cemco	Liquid Level	NBU 260	2
Cemco	Liquid Level	NBU 262	2
Cemco	Liquid Level	NBU 263	2
Cemco	Liquid Level	NBU 264	2
Cemco	Liquid Level	NBU 265	2
Cemco	Liquid Level	NBU 266	2
Cemco	Liquid Level	NBU 267	2
Cemco	Liquid Level	NBU 268	2
Cemco	Liquid Level	NBU 269	2
Cemco	Liquid Level	NBU 270 S.I.	2
Cemco	Liquid Level	NBU 271	2
Cemco	Liquid Level	NBU 272	1
Cemco	Liquid Level	NBU 273	2
Cemco	Liquid Level	NBU 274	2
Cemco	Liquid Level	NBU 275	2
Cemco	Liquid Level	NBU 277	2
Cemco	Liquid Level	NBU 280	2
Cemco	Liquid Level	NBU 281	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 282	2
Cemco	Liquid Level	NBU 285	2
Cemco	Liquid Level	NBU 286	2
Cemco	Liquid Level	NBU 287	2
Cemco	Liquid Level	NBU 288	2
Cemco	Liquid Level	NBU 289	2
Cemco	Liquid Level	NBU 290	2
Cemco	Liquid Level	NBU 291	2
Cemco	Liquid Level	NBU 292	2
Cemco	Liquid Level	NBU 293	2
Cemco	Liquid Level	NBU 294X	2
Cemco	Liquid Level	NBU 295	2
Cemco	Liquid Level	NBU 297	2
Cemco	Liquid Level	NBU 298	2
Cemco	Liquid Level	NBU 299	2
Cemco	Liquid Level	NBU 300	2
Cemco	Liquid Level	NBU 301	2
Cemco	Liquid Level	NBU 302	1
Cemco	Liquid Level	NBU 303	2
Cemco	Liquid Level	NBU 304	2
Cemco	Liquid Level	NBU 305	2
Cemco	Liquid Level	NBU 306	2
Cemco	Liquid Level	NBU 307	2
Cemco	Liquid Level	NBU 308	2
Cemco	Liquid Level	NBU 309	2
Cemco	Liquid Level	NBU 310	2
Cemco	Liquid Level	NBU 311	2
Cemco	Liquid Level	NBU 312-2E	2
Cemco	Liquid Level	NBU 313	2
Cemco	Liquid Level	NBU 315	2
Cemco	Liquid Level	NBU 316	2
Cemco	Liquid Level	NBU 318	2
Cemco	Liquid Level	NBU 321	2
Cemco	Liquid Level	NBU 322	2
Cemco	Liquid Level	NBU 326	2
Cemco	Liquid Level	NBU 327	1
Cemco	Liquid Level	NBU 329	1
Cemco	Liquid Level	NBU 330	2
Cemco	Liquid Level	NBU 333 SI	2
Cemco	Liquid Level	NBU 335	2
Cemco	Liquid Level	NBU 338	1
Cemco	Liquid Level	NBU 339	1
Cemco	Liquid Level	NBU 341	1
Cemco	Liquid Level	NBU 342	1
Cemco	Liquid Level	NBU 343	1
Cemco	Liquid Level	NBU 344	1
Cemco	Liquid Level	NBU 345	1
Cemco	Liquid Level	NBU 348	1
Cemco	Liquid Level	NBU 349	1
Cemco	Liquid Level	NBU 350	1
Cemco	Liquid Level	NBU 351	1

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 352	2
Cemco	Liquid Level	NBU 353	2
Cemco	Liquid Level	NBU 354	1
Cemco	Liquid Level	NBU 356	2
Cemco	Liquid Level	NBU 357	2
Cemco	Liquid Level	NBU 358	2
Cemco	Liquid Level	NBU 359	2
Cemco	Liquid Level	NBU 360	1
Cemco	Liquid Level	NBU 361	2
Cemco	Liquid Level	NBU 362	1
Cemco	Liquid Level	NBU 363X	2
Cemco	Liquid Level	NBU 364	2
Cemco	Liquid Level	NBU 365	1
Cemco	Liquid Level	NBU 367	1
Cemco	Liquid Level	NBU 370	2
Cemco	Liquid Level	NBU 371	2
Cemco	Liquid Level	NBU 375	2
Cemco	Liquid Level	NBU 376	2
Cemco	Liquid Level	NBU 378	2
Cemco	Liquid Level	NBU 381	1
Cemco	Liquid Level	NBU 384	2
Cemco	Liquid Level	NBU 390	1
Cemco	Liquid Level	NBU 391	2
Cemco	Liquid Level	NBU 392	2
Cemco	Liquid Level	NBU 394	2
Cemco	Liquid Level	NBU 395	1
Cemco	Liquid Level	NBU 396	1
Cemco	Liquid Level	NBU 398	2
Cemco	Liquid Level	NBU 404	1
Cemco	Liquid Level	NBU 405	2
Cemco	Liquid Level	NBU 406	2
Cemco	Liquid Level	NBU 407	1
Cemco	Liquid Level	NBU 408	2
Cemco	Liquid Level	NBU 412	1
Cemco	Liquid Level	NBU 413	1
Cemco	Liquid Level	NBU 414	2
Cemco	Liquid Level	NBU 418	2
Cemco	Liquid Level	NBU 419	2
Cemco	Liquid Level	NBU 420	2
Cemco	Liquid Level	NBU 421	2
Cemco	Liquid Level	NBU 422	1
Cemco	Liquid Level	NBU 423	1
Cemco	Liquid Level	NBU 424	1
Cemco	Liquid Level	NBU 425	1
Cemco	Liquid Level	NBU 426	1
Cemco	Liquid Level	NBU 427	1
Cemco	Liquid Level	NBU 428	2
Cemco	Liquid Level	NBU 434	2
Cemco	Liquid Level	NBU 435	2
Cemco	Liquid Level	NBU 436X	2
Cemco	Liquid Level	NBU 438	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 439	2
Cemco	Liquid Level	NBU 440	2
Cemco	Liquid Level	NBU 441	2
Cemco	Liquid Level	NBU 443	2
Cemco	Liquid Level	NBU 452	2
Cemco	Liquid Level	NBU 453	2
Cemco	Liquid Level	NBU 454	2
Cemco	Liquid Level	NBU 455	2
Cemco	Liquid Level	NBU 456	2
Cemco	Liquid Level	NBU 457	2
Cemco	Liquid Level	NBU 458	2
Cemco	Liquid Level	NBU 459	2
Cemco	Liquid Level	NBU 460	2
Cemco	Liquid Level	NBU 461	2
Cemco	Liquid Level	NBU 463	2
Cemco	Liquid Level	NBU 464	2
Cemco	Liquid Level	NBU 465	2
Cemco	Liquid Level	NBU 468	2
Cemco	Liquid Level	NBU 470	2
Cemco	Liquid Level	NBU 471	2
Cemco	Liquid Level	NBU 472	2
Cemco	Liquid Level	NBU 920-13C	2
Cemco	Liquid Level	NBU 920-22G	2
Cemco	Liquid Level	NBU 920-25D	2
Cemco	Liquid Level	NBU 921-12B	2
Cemco	Liquid Level	NBU 921-12C	2
Cemco	Liquid Level	NBU 921-12F	2
Cemco	Liquid Level	NBU 921-13A	2
Cemco	Liquid Level	NBU 921-13I	2
Cemco	Liquid Level	NBU 921-13M	2
Cemco	Liquid Level	NBU 921-13O	2
Cemco	Liquid Level	NBU 921-14I	2
Cemco	Liquid Level	NBU 921-14J	2
Cemco	Liquid Level	NBU 921-14M	2
Cemco	Liquid Level	NBU 921-14O	2
Cemco	Liquid Level	NBU 921-15N	2
Cemco	Liquid Level	NBU 921-15P	2
Cemco	Liquid Level	NBU 921-16A	2
Cemco	Liquid Level	NBU 921-17N	2
Cemco	Liquid Level	NBU 921-19G	2
Cemco	Liquid Level	NBU 921-19H	2
Cemco	Liquid Level	NBU 921-19I	2
Cemco	Liquid Level	NBU 921-20L	2
Cemco	Liquid Level	NBU 921-20N	2
Cemco	Liquid Level	NBU 921-20P	2
Cemco	Liquid Level	NBU 921-22A	2
Cemco	Liquid Level	NBU 921-22G	2
Cemco	Liquid Level	NBU 921-22L	2
Cemco	Liquid Level	NBU 921-23E	2
Cemco	Liquid Level	NBU 921-25D	2
Cemco	Liquid Level	NBU 921-27G	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	NBU 921-29K	2
Cemco	Liquid Level	NBU 921-29L	2
Cemco	Liquid Level	NBU 921-29M	2
Cemco	Liquid Level	NBU 921-29N	2
Cemco	Liquid Level	NBU 921-31A	2
Cemco	Liquid Level	NBU 921-31C	2
Cemco	Liquid Level	NBU 921-31D	2
Cemco	Liquid Level	NBU 921-33H	2
Cemco	Liquid Level	NBU 921-33I	2
Cemco	Liquid Level	NBU 921-34K	2
Cemco	Liquid Level	NBU 921-9G	2
Cemco	Liquid Level	NBU 921-9O	2
Cemco	Liquid Level	NBU 922-18K	2
Cemco	Liquid Level	NBU 922-18L	2
Cemco	Liquid Level	NBU 922-18N	2
Cemco	Liquid Level	NBU 922-18P	2
Cemco	Liquid Level	NBU 922-29M	2
Cemco	Liquid Level	NBU 922-30A	2
Cemco	Liquid Level	NBU 922-31I	2
Cemco	Liquid Level	NBU 922-33C	2
Cemco	Liquid Level	NBU 922-33D	2
Cemco	Liquid Level	NBU 922-33J	2
Cemco	Liquid Level	NBU 922-35K	2
Cemco	Liquid Level	NBU 922-36B	2
Cemco	Liquid Level	NBU 922-36C	2
Cemco	Liquid Level	NBU 922-36G	2
Cemco	Liquid Level	NBU 922-36H	2
Cemco	Liquid Level	NBU 922-36I	2
Cemco	Liquid Level	NBU 922-36N	2
Cemco	Liquid Level	NBU 922-36O	2
Cemco	Liquid Level	No Name Cyn. 1-9	1
Cemco	Liquid Level	No Name Cyn. 2-9	1
Cemco	Liquid Level	NSO Fed. 1-12	1
Cemco	Liquid Level	Ouray 1-101	2
Cemco	Liquid Level	Ouray 1-141	2
Cemco	Liquid Level	Ouray 33-90	2
Cemco	Liquid Level	Ouray 34-79	2
Cemco	Liquid Level	Ouray 35-174	2
Cemco	Liquid Level	Ouray 35-80	2
Cemco	Liquid Level	Ouray 35-94	2
Cemco	Liquid Level	Ouray 36-97	2
Cemco	Liquid Level	Sheepherder 1-10	1
Cemco	Liquid Level	Southman Canyon 9-4J	1
Cemco	Liquid Level	Southman Cyn 923-31B	2
Cemco	Liquid Level	Southman Cyn 923-31H	2
Cemco	Liquid Level	Southman Cyn 923-31J	2
Cemco	Liquid Level	Southman Cyn 923-31P	2
Cemco	Liquid Level	Southman Cyn. 04-5	1
Cemco	Liquid Level	Southman Cyn. 31-1L	2
Cemco	Liquid Level	Southman Cyn. 31-2X	2
Cemco	Liquid Level	Southman Cyn. 31-3	2

High-Bleed Devices – Uinta Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	Southman Cyn. 31-4	2
Cemco	Liquid Level	State 02-32	2
Cemco	Liquid Level	State 03-32	2
Cemco	Liquid Level	State 1021-36A	2
Cemco	Liquid Level	State 1021-36B	2
Cemco	Liquid Level	State 1022-32A	2
Cemco	Liquid Level	State 1022-32H	2
Cemco	Liquid Level	State 1022-32I	2
Cemco	Liquid Level	State 1022-32J	2
Cemco	Liquid Level	State 1022-32M	2
Cemco	Liquid Level	State 1022-32O	2
Cemco	Liquid Level	State 1022-32P	2
Cemco	Liquid Level	STATE 1022-36E	2
Cemco	Liquid Level	State 11-36	2
Cemco	Liquid Level	State 35-52	2
Cemco	Liquid Level	State 920-36O	2
Cemco	Liquid Level	State 920-36P	2
Cemco	Liquid Level	State 921-32L	2
Cemco	Liquid Level	State 921-32P	2
Cemco	Liquid Level	Tribal 02-50	2
Cemco	Liquid Level	Tribal 31-60	2
Cemco	Liquid Level	Tribal 36-148	2
Cemco	Liquid Level	UTD Kidd 20-16	3
Cemco	Liquid Level	Ute Trail 83X	2
Cemco	Liquid Level	Ute Trail 88X	2
Cemco	Liquid Level	Ute Tribal 01-54	2
Cemco	Liquid Level	Ute Tribal 35-19	2
Cemco	Liquid Level	Ute Tribal 35-51	2
Cemco	Liquid Level	Ute Tribal 36-17	2
Cemco	Liquid Level	Ute Tribal 36-65	2
Cemco	Liquid Level	Watts 923-1E	2
Cemco	Liquid Level	Weeks 6-154	2
Cemco	Liquid Level	WKRP 823-34A	2
Cemco	Liquid Level	Wonsit St. 2-32	2
Cemco	Liquid Level	Wonsit St. 5-32	2
Cemco	Liquid Level	Wonsit St. 9-32	2
Cemco	Liquid Level	Cottonwood/West	2
Cemco	Liquid Level	Morgan States	3
Cemco	Liquid Level	East	3
Cemco	Liquid Level	East Bench	2
Cemco	Liquid Level	Archie Bench	1
Cemco	Liquid Level	South	5
Cemco	Liquid Level	South Central	3
Cemco	Liquid Level	North	3
Cemco	Liquid Level	North East	1
Cemco	Liquid Level	L-16	2
Cemco	Liquid Level	Bonanza Central	3
Cemco	Liquid Level	Bonanza East	2
Cemco	Liquid Level	Bonanza West	2
Cemco	Liquid Level	East Jr.	1

APPENDIX H

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

HIGH-BLEED PNEUMATIC CONTROLLERS IN THE D-J BASIN TO BE RETROFITTED WITH LOW-BLEED PNEUMATIC CONTROLLERS

Overview and Purpose

Kerr-McGee has agreed to retrofit certain high-bleed Pneumatic Controllers in the D-J Basin as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.E., Kerr-McGee will retrofit the following high-bleed Pneumatic Controllers in the D-J Basin with low-bleed Pneumatic Controllers:

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	VIOLA 16-36 - VIOLA 9-36A	1
Cemco	Liquid Level	AXELSON 24-19	1
Cemco	Liquid Level	SARCHET, M 3-35A - SARCHET, M 4-35A	1
Cemco	Liquid Level	BARCLAY 44-14	1
Cemco	Liquid Level	BEDDO 4-25X - BEDDO 5-25	1
Cemco	Liquid Level	BERNHARD 4-23A - STREAR 22-23	1
Cemco	Liquid Level	PRYMACK GU 1	1
Cemco	Liquid Level	BERRY 11-26A - BERRY 26-12L	1
Cemco	Liquid Level	MAGNESS 44-25	1
Cemco	Liquid Level	MAGNESS 43-25	1
Cemco	Liquid Level	CAMP 1-24 - CAMP 2-24 - CAMP 7-24	1
Cemco	Liquid Level	CAMP 13-19A - PLATTEVILLE 23-19A	1
Cemco	Liquid Level	GORDON FARMS 21-15 - SCHIS 5-15A	1
Cemco	Liquid Level	CAROL MILLER 3-31 - CAROL MILLER 5-31 - CAROL MILLER 6-31	1
Cemco	Liquid Level	CHARLENE 2-36 - CHARLENE 2-36A - NISHIMOTO 7-36	1
Cemco	Liquid Level	DAVIS, V. 5-26A - DAVIS, V. 6-26A	1
Cemco	Liquid Level	ABBETT 1-23A	1
Cemco	Liquid Level	ABBETT 7-23 - ABBETT 8-23A	1
Cemco	Liquid Level	ACCORD 16-30 - REYNOLDS 9-30	1
Cemco	Liquid Level	ACORD 11-29 - ACORD 14-29	1
Cemco	Liquid Level	WADDLE 24-5L	1
Cemco	Liquid Level	WADDLE 24-10J7	1
Cemco	Liquid Level	WADDELL 13-24A	1
Cemco	Liquid Level	ALMQUIST MB 34-1 - VAN THUYNE 42-34	1
Cemco	Liquid Level	STROMQUIST ARTHUR 2 - WESTERN 3-21A	1
Cemco	Liquid Level	STATE 16-13J7	1
Cemco	Liquid Level	STATE 16-12L - STATE 16-14L	1
Cemco	Liquid Level	SMITH 11-34 - SMITH 12-34	1
Cemco	Liquid Level	SERAFINI E MAX GU 1	1
Cemco	Liquid Level	B/R B 13-21A - B/R B 14-21	1
Cemco	Liquid Level	B/R B 3-21 - B/R B 4-21	1
Cemco	Liquid Level	B/R C 1-29 - B/R C 8-29	1
Cemco	Liquid Level	B/R D 7-20 - B/R D 8-20	1
Cemco	Liquid Level	SEKICH FARMS II UN 1	1
Cemco	Liquid Level	SEKICH FARMS 16-18	1

High-Bleed Devices – D-J Basin			
Style	Service	Location / Facility Name	Number of Devices
Cemco	Liquid Level	SEKICH FARMS 1-20A - SEKICH FARMS 2-20	1
Cemco	Liquid Level	SEKICH FARMS 10-18 - SEKICH FARMS 9-18	1
Cemco	Liquid Level	SEKICH A 16-17 - SEKICH A 9-17	1
Cemco	Liquid Level	SEKICH A 11-17A - SEKICH A 14-17	1
Cemco	Liquid Level	SEKICH A 10-17 - SEKICH A 15-17	1
Cemco	Liquid Level	SEKICH 4-19 - SEKICH 5-19	1
Wellmark	Liquid Level	BALDWIN ROBERT UT 2 - DODERO 6-4A	1
Cemco	Liquid Level	SARCHET 33-9L - SARCHET MILDRED UN 1	1
Cemco	Liquid Level	SALAZAR 6-20 - SALAZAR 6-20AX - SEKICH FARMS 3-20A	1
Cemco	Liquid Level	SALAZAR 5-20 - SEKICH FARMS 4-20	1
Cemco	Liquid Level	REYNOLDS 1-30XXA - REYNOLDS 8-30	1
Cemco	Liquid Level	REDMOND 12-21	1
Cemco	Liquid Level	RADEMACHER 2-30 - RADEMACHER 7-30X	1
Cemco	Liquid Level	RADEMACHER 12-30 - RADEMACHER 13-30	1
Cemco	Liquid Level	RADEMACHER 11-30A - RADEMACHER 14-30	1
Cemco	Liquid Level	PSC 14-13	1
Cemco	Liquid Level	PERCONTE 16-23 - PIZ 15-23A	1
Cemco	Liquid Level	NELSON MILTON H I1 - NELSON MILTON H K1 - NELSON MILTON H L1	1
Cemco	Liquid Level	MUHME 6-30A	1
Cemco	Liquid Level	MILLER 27-12L	1
Cemco	Liquid Level	MCHALE 7-5A	1
Cemco	Liquid Level	MCGREGOR 6-28 - SHERRY 5-28	1
Cemco	Liquid Level	MCEWEN 3-28A - NADER 4-28A	1
Cemco	Liquid Level	MCDANIELS 4-22 - WILLIAM MAYER 5-22A	1
Cemco	Liquid Level	MCCLAY 11-34A - MCCLAY 14-34A	1
Cemco	Liquid Level	MAYER 6-22A - WILLIAM MAYER 3-22A	1
Cemco	Liquid Level	MAYER 22-16L	1
Cemco	Liquid Level	MAYER 22-13L - WEBBER JOSEPH UT 1	1
Cemco	Liquid Level	MAYER 11-15 - MAYER 4-15	1
Cemco	Liquid Level	MAYER 10-23 - MAYER 9-23AX	1
Cemco	Liquid Level	LOWES 6-21A - WEIS 5-21A	1
Cemco	Liquid Level	KUECHLER 11-23 - LEMON 12-23A	1
Cemco	Liquid Level	BUTCH 3-19 - SEKICH 3-19A - SEKICH 6-19	1
Cemco	Liquid Level	KITELEY 5-27 - VALLEY 66 UNIT 2	1
Cemco	Liquid Level	HOUSTON B 5-16 - HOUSTON B 6-16	1
Cemco	Liquid Level	HOUSTON B 3-16A - HOUSTON B 4-16	1
Cemco	Liquid Level	HOPPER 10-15A - HOPPER 43-15A	1
Cemco	Liquid Level	HINDMAN 12-34 - MCCARTY MB 34-3	1
Cemco	Liquid Level	HEINTZELMAN 16-32 - HEINTZELMAN 9-32	1
Cemco	Liquid Level	HEINTZELMAN 1-32 - HEINTZELMAN 8-32A	1
Cemco	Liquid Level	GLEN 13-23A - RANDY 14-23	1
Cemco	Liquid Level	FIRESTONE 12-30	1
Cemco	Liquid Level	COADY 12-28A - NIX 13-28	1
Cemco	Liquid Level	COGBURN 2-29A - COGBURN 7-29	1
Cemco	Liquid Level	COGBURN 3-29 - COGBURN 6-29	1
Cemco	Liquid Level	COGBURN 4-29 - COGBURN 5-29	1
Cemco	Liquid Level	ELVERNA 11-28 - KURTZ AL GU 1 - NIX 14-28	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	DILLON 44-15 - EAST RINN 1	1
Cemco	Liquid Level	DEL CAMINO 11-14 - OLANDER 1-14	1
Cemco	Liquid Level	DACONO 11-36 - STATE 1	1
Cemco	Liquid Level	WISE 31-14	1
Cemco	Liquid Level	ALMQUIST 41-10	1
Cemco	Liquid Level	TWIN CORNERS 4-14	1
Cemco	Liquid Level	STONEHOCKER 31-7	1
Cemco	Liquid Level	SELTZER 23-3	1
Cemco	Liquid Level	SCHNEIDER FARM 33-33	1
Cemco	Liquid Level	BASELINE 21-2	1
Cemco	Liquid Level	MUSE 1 - SEATON 8-18	1
Cemco	Liquid Level	JASPER 23-14	1
Cemco	Liquid Level	CHAMPLIN 86 AMOCO G1 - CHAMPLIN 86 AMOCO K1 - CHAMPLIN 86 AMOCO L1 - CHAMPLIN 86 AMOCO O9 - KOCH KENNETH E A-1	1
Cemco	Liquid Level	CHRISTIANSEN 12-9	1
Cemco	Liquid Level	CLARK FRANCIS UT B 2 - HIGHUM FOUNDERS 1	1
Cemco	Liquid Level	UPRR 22 PA F TRUE 1	1
Cemco	Liquid Level	UPRC 9-6K	1
Cemco	Liquid Level	UPRC 31-14K - UPRC 31-16K	1
Cemco	Liquid Level	UPRC 29-14K - UPRR 42 PAN AM 1	1
Cemco	Liquid Level	UPRC 29-13K	1
Cemco	Liquid Level	UPRC 29-12K	1
Cemco	Liquid Level	UPRC 15-14K - UPRC 15-4K2	1
Cemco	Liquid Level	TOOMBS 14-28A	1
Cemco	Liquid Level	STEWART 3-28A	1
Cemco	Liquid Level	ANTENNA-FED 11-36 - FEDERAL 3-36	1
Cemco	Liquid Level	STATE - OLIN 3	1
Cemco	Liquid Level	SILVERS 9-33A - TRIMBLE 10-33A	1
Cemco	Liquid Level	ATHERTON 5-20A - BERNSTEIN 6-20A	1
Cemco	Liquid Level	AVINS 6-29	1
Wellmark	Liquid Level	BALDWIN 12-28A	1
Cemco	Liquid Level	BARCLAY 2-28 - TELISCHAK 8-28	1
Cemco	Liquid Level	SAMUELSEN 3-24	1
Cemco	Liquid Level	SAKATA RED W 6-8	1
Cemco	Liquid Level	ROZEMA 4-26A - RUSSELL 3-26A	1
Cemco	Liquid Level	RENSHAW 5-28A	1
Cemco	Liquid Level	PURYEAR 5-29X - SABS 4-29	1
Cemco	Liquid Level	BEIERLE 14-26 - CAMPBELL 12-26A	1
Cemco	Liquid Level	BLUFFS WHITE W 5-2 - BLUFFS WHITE W 5-8	1
Cemco	Liquid Level	MILLER UPRR 41-29	1
Cemco	Liquid Level	MILLER FEDERAL 15-6A	1
Cemco	Liquid Level	MILLER 6-33A	1
Cemco	Liquid Level	MADELINE MAYER 11-34 - MADELINE MAYER 12-34 - ZELDIN 14-34	1
Cemco	Liquid Level	BROTEMARKLE 6-24 - MORSE 6-24	1
Cemco	Liquid Level	LANDOR 10-22A - ROBERTS 15-22	1
Cemco	Liquid Level	KUGEL 31-23A	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	KARICH 2-32 - KARICH 2-32A	1
Cemco	Liquid Level	KARICH 1-32 - KARICH 7-32 - KARICH 8-32	1
Cemco	Liquid Level	JERRY D 11-28A - STEWART 3-28A	1
Cemco	Liquid Level	CANNON 10-35	1
Cemco	Liquid Level	HIGGINS 14-23A	1
Cemco	Liquid Level	HERMAN UPRR 31-31 1	1
Cemco	Liquid Level	CANNON 9-18A - CLC GU 2	1
Cemco	Liquid Level	HARTELL 16-22A	1
Cemco	Liquid Level	GLASSER 1-21A - PICCONE 2-21X	1
Cemco	Liquid Level	FEDERAL 16-36 - FEDERAL 9-36	1
Cemco	Liquid Level	FEDERAL 1-36 - FEDERAL 7-36 - FEDERAL 8-36	1
Cemco	Liquid Level	FEDERAL 11-36 - FEDERAL 14-36	1
Cemco	Liquid Level	FAUST 13-21A - POE 12-21A	1
Cemco	Liquid Level	ELTON MILLER 3-7A - MILLER ELTON GU B 2	1
Cemco	Liquid Level	DAVID SARCHET 16-28 - SARCHET 9-28A	1
Cemco	Liquid Level	SARCHET 2	1
Cemco	Liquid Level	SARCHET 1	1
Cemco	Liquid Level	CANNON LAND 6-3A - UPRR 38 PAN AM E 2	1
Cemco	Liquid Level	EICHTHALER 2	1
Cemco	Liquid Level	COOKSEY LYLE V 1	1
Cemco	Liquid Level	DOLPH UPRR 32-1 - DOLPH UPRR 42-1	1
Cemco	Liquid Level	WIEDEMAN 16-20 - WIEDEMAN 9-20	1
Cemco	Liquid Level	WIEDEMAN 14-20	1
Cemco	Liquid Level	WIEDEMAN 10-20 - WIEDEMAN 15-20	1
Cemco	Liquid Level	ACHZIGER 11-33	1
Cemco	Liquid Level	WEBSTER 11-32	1
Cemco	Liquid Level	WASS 3X - WASS 5	1
Cemco	Liquid Level	WASS 1	1
Cemco	Liquid Level	WARDLAW 33-28 - WEBSTER 9-28	1
Cemco	Liquid Level	VICTOR G 14-12 - VICTOR G 14-14	1
Cemco	Liquid Level	ALEXANDER 2-10 - MEAD 7-10	1
Cemco	Liquid Level	ALLEN 41-12	1
Cemco	Liquid Level	ALLES JOHN 1 - LOEFFLER 8-27	1
Cemco	Liquid Level	ALVA SHABLE 1-4	1
Cemco	Liquid Level	ALVA SHABLE 2-4	1
Cemco	Liquid Level	ANDERSON 3-3 - KNOX 4-3	1
Cemco	Liquid Level	TIMMERMAN 13-13 - WERTZ 14-13	1
Cemco	Liquid Level	SWINNEY 1-15 - SWINNEY 2	1
Cemco	Liquid Level	STRONG 6-31	1
Cemco	Liquid Level	ANDERSON-COOMBS 2	1
Cemco	Liquid Level	ANDERSON-COOMBS 4 - ANDERSON-COOMBS 5	1
Cemco	Liquid Level	STENZEL 1-31	1
Cemco	Liquid Level	STATE-ELK 1 - STATE-HUME 1	1
Cemco	Liquid Level	SPOMER 7-32	1
Cemco	Liquid Level	SPOMER 7-32	1
Cemco	Liquid Level	SPOMER 2-32	1
Cemco	Liquid Level	SPOMER 10-32 - SPOMER 9-32	1
Cemco	Liquid Level	SITZMAN 13-33	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	SEYLER 41-14	1
Cemco	Liquid Level	SEYLER 2-14	1
Cemco	Liquid Level	BACON 11-34	1
Cemco	Liquid Level	BACON 3	1
Cemco	Liquid Level	SANDUSKY 1	1
Cemco	Liquid Level	ROTHE 1-24 - ROTHE 8-24	1
Cemco	Liquid Level	ROADIFER 12-12B	1
Cemco	Liquid Level	REED 42-34	1
Cemco	Liquid Level	RAISLEY 44-27	1
Cemco	Liquid Level	RAISLEY 34-27	1
Cemco	Liquid Level	RAISLEY 21-34	1
Cemco	Liquid Level	BENSON 13-15	1
Cemco	Liquid Level	PINNACLE PARK 13-14	1
Cemco	Liquid Level	BERTLIN 1-10 - MENK 8-10	1
Cemco	Liquid Level	BETZ 1	1
Cemco	Liquid Level	BETZ 2	1
Cemco	Liquid Level	BIG FOOT 1-12	1
Cemco	Liquid Level	BIG FOOT 14-12	1
Cemco	Liquid Level	PEANUT 1	1
Cemco	Liquid Level	OSTER 24-15	1
Cemco	Liquid Level	NIES 16-15 - NIES 9-15	1
Cemco	Liquid Level	NIES 10-15 - NIES 15-15	1
Cemco	Liquid Level	BLISS 13-34	1
Cemco	Liquid Level	BLISS 14-3 - GLENDENNING 13-3	1
Cemco	Liquid Level	BLISS 15-33	1
Cemco	Liquid Level	NELSON 12-22 - NELSON 13-22	1
Cemco	Liquid Level	MOORE UPRC G 15-7 - MOORE UPRC G 15-8	1
Cemco	Liquid Level	MOORE UPRC C 19-2 - MOORE UPRC C 19-7	1
Cemco	Liquid Level	MILLER 16-29	1
Cemco	Liquid Level	MILLARD 9-29 - ONEIL 16-29	1
Cemco	Liquid Level	BOREN 2-32	1
Cemco	Liquid Level	BORESEN 1	1
Cemco	Liquid Level	MCDERMED 2-1	1
Cemco	Liquid Level	BOULTER FRANK A 1	1
Cemco	Liquid Level	MCALLISTER 32-12	1
Cemco	Liquid Level	BRANCH 1-3	1
Cemco	Liquid Level	BRANTNER 1 - BRANTNER 3	1
Cemco	Liquid Level	BRANTNER 2	1
Cemco	Liquid Level	LUNDVALL 1-13 - MOORE 10-13 - MOORE 9-13	1
Cemco	Liquid Level	LEY 7-19	1
Cemco	Liquid Level	LEONARD 12-15 - LEONARD 13-15	1
Cemco	Liquid Level	LEONARD 11-15 - LEONARD 14-15	1
Cemco	Liquid Level	LEHAN 1 - WCL 34-5	1
Cemco	Liquid Level	LASALLE 14-29	1
Cemco	Liquid Level	LANDOR 10-22A - ROBERTS 15-22 - VICTOR C 19-9	1
Cemco	Liquid Level	BUCKLEN 12-31	1
Cemco	Liquid Level	BUCKLEN 9-36	1
Cemco	Liquid Level	KRAMER 2-27	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	KOHLER 6-21 - KOHLER 7-21 - KOHLER 8-21	1
Cemco	Liquid Level	BUNTING 4-35 - BUNTING 5-35	1
Cemco	Liquid Level	KNOX 5-3 - KNOX 6-3	1
Cemco	Liquid Level	KNOX 15-3 - KNOX 16-3	1
Cemco	Liquid Level	KNOX 12-3 - KNOX 13-3	1
Cemco	Liquid Level	KNOX 11-3 - KNOX 14-3	1
Cemco	Liquid Level	KNOX 10-3 - KNOX 9-3	1
Cemco	Liquid Level	KINZER 5-23 - KINZER 6-23	1
Cemco	Liquid Level	KINZER 3-23 - KINZER 4-23	1
Cemco	Liquid Level	KEITH 1	1
Cemco	Liquid Level	KEATON 8-26	1
Cemco	Liquid Level	KARRE 9-15 - RICHARDSON BR UT B 1	1
Cemco	Liquid Level	JONES SETH UNIT 1	1
Cemco	Liquid Level	JERKE 1-15 - OSTER 13-15	1
Cemco	Liquid Level	ISHIGURO 6	1
Cemco	Liquid Level	ISHIGURO 3 - ISHIGURO 4	1
Cemco	Liquid Level	ISHIGURO 2	1
Cemco	Liquid Level	ISHIGURO 1	1
Cemco	Liquid Level	HUNTER 1	1
Cemco	Liquid Level	HOSHIKO 7-2	1
Cemco	Liquid Level	HOSHIKO 3-33	1
Cemco	Liquid Level	HOP ANDREW UNIT 1	1
Cemco	Liquid Level	HOECHER 2	1
Cemco	Liquid Level	HOECHER 1 - WILKINSON 1	1
Cemco	Liquid Level	HERBSTER 3-35	1
Cemco	Liquid Level	HEPPBERGER 11-24	1
Cemco	Liquid Level	GUY SHABLE INC 4-4 - GUY SHABLE INC. 1-4	1
Cemco	Liquid Level	GEISERT 7-11	1
Cemco	Liquid Level	GARCIA UPRR 31-5	1
Cemco	Liquid Level	FREEDOM TWO C 19-3 - FREEDOM TWO C 19-4	1
Cemco	Liquid Level	FREEDOM ONE C 19-5 - FREEDOM TWO C 19-6	1
Cemco	Liquid Level	FRANCEN 11-30	1
Cemco	Liquid Level	FOE 43-20	1
Cemco	Liquid Level	FOE 16-20	1
Cemco	Liquid Level	FLATIRON 10-36	1
Cemco	Liquid Level	FLACK 7-19	1
Wellmark	Liquid Level	FIOLKOSKI 2-26 - FIOLKOSKI 24-26	1
Cemco	Liquid Level	CHITTENDEN 2-32	1
Cemco	Liquid Level	CHRISTENSEN 15-18 - CHRISTENSEN 16-18	1
Cemco	Liquid Level	CHRISTENSEN 2-19	1
Cemco	Liquid Level	CITY OF GREELEY 2-30	1
Cemco	Liquid Level	FAIRMEADOWS 12-3	1
Cemco	Liquid Level	CLEMONS 2-3	1
Cemco	Liquid Level	ELLA 1	1
Cemco	Liquid Level	DOS RIOS J 33-10	1
Cemco	Liquid Level	DOS RIOS 41-34	1
Cemco	Liquid Level	DOS RIOS 14-34	1
Cemco	Liquid Level	CROISSANT 1 - CROISSANT 11-20	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CROISSANT 2	1
Cemco	Liquid Level	DAVIS 7-4	1
Cemco	Liquid Level	WEISS 1-34	1
Cemco	Liquid Level	SWANK 41-11 - SWANK 42-11	1
Cemco	Liquid Level	SPAUR 7-7X - SPAUR O 7-8	1
Cemco	Liquid Level	SPAUR 1-7 - SPAUR 2-7	1
Cemco	Liquid Level	SHULTZ STATE 16-1 - SHULTZ STATE 16-8	1
Cemco	Liquid Level	SELBY 2-32 - SELBY 7-32 - SELBY 8-32	1
Cemco	Liquid Level	SELBY 1-32 - SELBY POOLING UNIT 1	1
Cemco	Liquid Level	SEEWALD 11-31	1
Cemco	Liquid Level	SCOTTDALE RANCH13-35 - SCOTTDALE RANCH14-35	1
Cemco	Liquid Level	SCOTTDALE RANCH 7-2 - SCOTTDALE RANCH 8-2	1
Cemco	Liquid Level	SCHNEIDER 12-35 - SCHNEIDER 4-35	1
Cemco	Liquid Level	BALLINGER 4-18	1
Cemco	Liquid Level	SCHLAGEL 13-4 - SCHLAGEL 14-4 - SCHLAGEL 23-4	1
Cemco	Liquid Level	SCHELL 12-5 - SCHELL 13-5	1
Cemco	Liquid Level	SCHELL 11-5 - SCHELL 14-5	1
Cemco	Liquid Level	SANDBERG 2-6 - SANDBERG 7-6	1
Cemco	Liquid Level	BASSETT 5-18 - PFISTER 3-18 - ROTH 6-18	1
Cemco	Liquid Level	PSC 44-10	1
Cemco	Liquid Level	PSC 41-3 - PSC 9-3	1
Cemco	Liquid Level	PSC 34-34	1
Cemco	Liquid Level	PSC 33-11 - PSC 43-11A	1
Cemco	Liquid Level	PSC 32-9	1
Cemco	Liquid Level	PSC 32-10	1
Cemco	Liquid Level	PSC 23-11A	1
Cemco	Liquid Level	BEIN 1	1
Cemco	Liquid Level	PSC 22-11 - PSC 32-11A	1
Cemco	Liquid Level	PSC 21-11A	1
Cemco	Liquid Level	PSC 2-11 - SWANK N L 1	1
Cemco	Liquid Level	PSC 16-9X - PSC 43-9A	1
Cemco	Liquid Level	PSC 16-34 - PSC 43-34	1
Cemco	Liquid Level	PSC 14-9 - PSC 23-9A	1
Cemco	Liquid Level	PSC 12-9 - PSC 22-9	1
Cemco	Liquid Level	PSC 12-2	1
Cemco	Liquid Level	BERNHARDT 1-1 - HULL 1-1	1
Cemco	Liquid Level	BERNHARDT 3-36 - VETTER 12-36 - VETTER 13-36	1
Cemco	Liquid Level	PODTBURG S 2	1
Cemco	Liquid Level	BERNIE 4-17 - JACKIE 3-17A	1
Cemco	Liquid Level	PESCO 4-11 - PESCO 5-11	1
Cemco	Liquid Level	PESCO 13-2A	1
Cemco	Liquid Level	BERRY 2-8 - BERRY 7-8	1
Cemco	Liquid Level	BERRY 41-8	1
Cemco	Liquid Level	PALMER 12-8 - PALMER 13-8	1
Cemco	Liquid Level	PALMER 11-8 - PALMER 14-8	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	MST 11-3	1
Cemco	Liquid Level	BOOTH 13-26	1
Cemco	Liquid Level	BOOTH 33-26	1
Cemco	Liquid Level	MCLAUGHLIN 34-8	1
Cemco	Liquid Level	LIZ 5-17 - SEKICH A 6-17	1
Cemco	Liquid Level	LEBERMAN 16-1 - ODENBAUGH 15-1A	1
Cemco	Liquid Level	KOESTER 14-33 - KOESTER 23-33 - KOESTER 24-33	1
Cemco	Liquid Level	CAMENISCH 33-33 - CAMENISCH 43-33	1
Cemco	Liquid Level	KAMMERZELL 15-25 - KAMMERZELL 16-25	1
Cemco	Liquid Level	JOHNSON 1-34 - JOHNSON 3-34 - WEISS 13-34	1
Cemco	Liquid Level	JOHNNY B. GOOD 15-6 - TANIDA 10-6	1
Cemco	Liquid Level	JACKSON 43-8A - MCLAUGHLIN 16-8	1
Cemco	Liquid Level	HUFFMAN 9-2A	1
Cemco	Liquid Level	HART - MEMCO 1-22	1
Cemco	Liquid Level	HALVERSON 1	1
Cemco	Liquid Level	GREENHEAD 32-18	1
Cemco	Liquid Level	GREENHEAD 11-18 - GREENHEAD 14-18	1
Cemco	Liquid Level	GRAY STATE 16-6	1
Cemco	Liquid Level	GOLDSMITH 11-31 - JENKINS 14-31	1
Cemco	Liquid Level	FT ST VRAIN 7 - MCDONALD 5-3A	1
Cemco	Liquid Level	FT ST VRAIN 4	1
Cemco	Liquid Level	FT ST VRAIN 29 - FT ST VRAIN 6	1
Cemco	Liquid Level	FT ST VRAIN 23 - PSC 14-3A	1
Cemco	Liquid Level	FT ST VRAIN 21 - FT ST VRAIN 25	1
Cemco	Liquid Level	FT ST VRAIN 2 - PSC 34-9	1
Cemco	Liquid Level	FT ST VRAIN 18	1
Cemco	Liquid Level	FT ST VRAIN 14	1
Cemco	Liquid Level	FT ST VRAIN 12	1
Cemco	Liquid Level	FT ST VRAIN 1 - FT ST VRAIN 26	1
Cemco	Liquid Level	FREAUFF 33-4A - FREAUFF 34-4	1
Cemco	Liquid Level	FREAUFF 1 - FREAUFF 43-4	1
Cemco	Liquid Level	FRANK 6-14 - KNAUB-BETZ 2-14	1
Cemco	Liquid Level	FELDMAN 1-36 - GRAHAM 2-36	1
Cemco	Liquid Level	CLACK 1-2A - OLSON 2-2	1
Cemco	Liquid Level	ELLIOT FARMS 2-18A - ELLIOT FARMS 7-18	1
Cemco	Liquid Level	CONNIE 1-18 - MARGARET 8-18	1
Cemco	Liquid Level	EHRLICH 3-18 - EHRLICH 6-18	1
Cemco	Liquid Level	DUNKLEE 3 - MICHALL 4-13	1
Cemco	Liquid Level	DORSA 3-1 - WALTER 6-1A	1
Cemco	Liquid Level	DERDIVANIS 3-2 - HEIMARK 6-2	1
Cemco	Liquid Level	WETCO FARM UPRR 43-3	1
Cemco	Liquid Level	WERTZ 24-12	1
Cemco	Liquid Level	WEBBER UPRR 31-3	1
Cemco	Liquid Level	WEBBER 11-4	1
Cemco	Liquid Level	UPRR 21 PAN AM K 1	1
Wellmark	Liquid Level	UNI - UPRC 15-3	1
Cemco	Liquid Level	TUTTLE 5-8A - TUTTLE 6-8	1
Cemco	Liquid Level	TUTTLE 4-8	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	TUTTLE 31-7 J - TUTTLE 32-7	1
Cemco	Liquid Level	TUTTLE 15-7	1
Cemco	Liquid Level	ANDERSON 8-9 - DILL 42-9R 1	1
Cemco	Liquid Level	THOMPSON 44-6A	1
Cemco	Liquid Level	THOMPSON 33-6A - THOMPSON 43-6	1
Cemco	Liquid Level	STROMBERGER 32-12	1
Cemco	Liquid Level	STROMBERGER 31-12	1
Cemco	Liquid Level	STROMBERGER 21-12	1
Cemco	Liquid Level	STREED 10-13 - STREED 15-13A	1
Cemco	Liquid Level	API 31-15 - API 41-15	1
Wellmark	Liquid Level	API 32-15 - API 42-15	1
Cemco	Liquid Level	STANLEY ODENB 12-12	1
Cemco	Liquid Level	SARATOGA 1	1
Cemco	Liquid Level	SALAMANCA FRANK GU 1	1
Cemco	Liquid Level	BECKER 1 - SANDAU 24-34	1
Cemco	Liquid Level	BELL 12-5 - CREASON 11-5	1
Cemco	Liquid Level	PRESLEY 10-6K - WEBBER EDITH 2	1
Cemco	Liquid Level	PRESLEY 10-3K	1
Cemco	Liquid Level	PHELPS 8-18	1
Wellmark	Liquid Level	PEPPLER 2-36 - PEPPLER 3-36	1
Cemco	Liquid Level	PEPPLER 16-35 - PEPPLER 9-35	1
Wellmark	Liquid Level	PEPPLER 1-36	1
Cemco	Liquid Level	BLAKE 13-12 - BLAKE 23-12	1
Cemco	Liquid Level	ODENBAUGH CULL UT 1 - STANLEY ODENB 13-12	1
Wellmark	Liquid Level	NOFFSINGER 44-15	1
Cemco	Liquid Level	NOFFSINGER 13-14 - NOFFSINGER 23-14	1
Wellmark	Liquid Level	MONFORT 5-10 - MONFORT 6-10	1
Cemco	Liquid Level	MILLER ESTATE 8-14K	1
Cemco	Liquid Level	MILE HIGH 13-3	1
Cemco	Liquid Level	MCGLOTHLIN 24-6	1
Cemco	Liquid Level	BOULTER FED 12-18 - BOULTER FED 14-18	1
Cemco	Liquid Level	MCCLELLAN 44-20	1
Cemco	Liquid Level	MCCLELLAN 33-20	1
Cemco	Liquid Level	MCCARTHY 11-12	1
Cemco	Liquid Level	M J FARMS 14-7	1
Cemco	Liquid Level	LORENZ UPRR 41-27 3 - LORENZ UPRR 42-27 1	1
Cemco	Liquid Level	LORENZ CHRIS A 1	1
Cemco	Liquid Level	LORENZ CHRIS 1	1
Cemco	Liquid Level	BROWN 44-24	1
Cemco	Liquid Level	CALLOW JAMES E GU 1	1
Cemco	Liquid Level	KEISER 13-28	1
Cemco	Liquid Level	KAWATA 2-16	1
Cemco	Liquid Level	JOHNSON GU 1	1
Cemco	Liquid Level	JOHNSON 6-30	1
Cemco	Liquid Level	HILDENBRANDT POOL 1	1
Cemco	Liquid Level	HALE 2-13 - TOOMEY 7-13	1
Cemco	Liquid Level	GUTFELDER AMOC 24-19	1
Cemco	Liquid Level	GUTFELDER 3-30 - GUTFELDER 4-30	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	GUNZNER 11-13A - GUNZNER 14-13	1
Wellmark	Liquid Level	CARNEY 31-4 1	1
Cemco	Liquid Level	CHADIMA 4-14 - CHRISTY 3-14	1
Cemco	Liquid Level	FAGERBERG 32-14 1	1
Wellmark	Liquid Level	EWING 41-14	1
Cemco	Liquid Level	EWING 33-15 - EWING 34-15	1
Wellmark	Liquid Level	EWING 33-10 - MEYERS 34-10	1
Wellmark	Liquid Level	EWING 31-14	1
Wellmark	Liquid Level	EWING 21-14 - FAGERBERG 22-14	1
Cemco	Liquid Level	CLEMENT 34-11 - CLEMENT 44-11	1
Cemco	Liquid Level	EWING 11-14 - FAGERBERG 12-14	1
Cemco	Liquid Level	DOS RIOS 43-34 - RUMSEY 16-34	1
Cemco	Liquid Level	DINNER K 13-2 - DINNER UP 1-13	1
Cemco	Liquid Level	DINNER 42-14 1	1
Cemco	Liquid Level	DINNER 13-18A - DINNER 14-18	1
Cemco	Liquid Level	CULLEN ODENB 11-12A - CULLEN ODENB 14-12	1
Cemco	Liquid Level	WARDELL 11-18	1
Cemco	Liquid Level	VICTOR C 29-16 - VICTOR C 29-9	1
Cemco	Liquid Level	VICTOR C 29-12	1
Cemco	Liquid Level	VICTOR C 29-11 - VICTOR C 29-14	1
Cemco	Liquid Level	UPRC 31-16G	1
Cemco	Liquid Level	ANDERSON 12-27 - BOHLENDER 1-27	1
Cemco	Liquid Level	TUTTLE 31-7 J - PALLETTE 10-9	1
Cemco	Liquid Level	ANDERSON 41-27 - BOHLENDER 2-27	1
Cemco	Liquid Level	STROMBERGER 44-12	1
Cemco	Liquid Level	RURAL LAND 32-31 2	1
Cemco	Liquid Level	RUPERT G 25-5	1
Cemco	Liquid Level	RAFALOVICH 14-5 - REAM 15-5A	1
Cemco	Liquid Level	BEEBE DRAW 14-10 - OVIATT 11-10	1
Cemco	Liquid Level	BEEBE DRAW 3-15 - BEEBE DRAW 4-15	1
Cemco	Liquid Level	BEEBE DRAW 41-15 2 - BEEBEDRW CATL32-15 1	1
Cemco	Liquid Level	BEEBE DRAW UPRR 41-5	1
Cemco	Liquid Level	BEEBE DRAW UPRR 41-9	1
Cemco	Liquid Level	PERRY 15-9A - RICHARDS 16-9A	1
Cemco	Liquid Level	OSTER 13-22	1
Cemco	Liquid Level	OGG 5-28 - PEARSON 1	1
Cemco	Liquid Level	OGG 21-28 - OGG 22-28	1
Cemco	Liquid Level	OGG 11-28	1
Cemco	Liquid Level	NICHOLS 15-32	1
Cemco	Liquid Level	MORTON 9-9A - PALLETTE 10-9	1
Cemco	Liquid Level	LUHMAN UPRR 42-13 4	1
Cemco	Liquid Level	LUHMAN UPRR 41-13A - UPRR 22 PAN AM H 1	1
Cemco	Liquid Level	BROSNAHAN 13-30	1
Cemco	Liquid Level	KRAUSE 1-28	1
Cemco	Liquid Level	KNAUB 22-27 - OSTER 21-27	1
Cemco	Liquid Level	KINSMAN 23-18 - KINSMAN 33-18 - KINSMAN 34-18	1
Cemco	Liquid Level	KINSMAN 22-18	1
Cemco	Liquid Level	HENNINGTON C 32-7	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	HENNINGTON C 32-10	1
Cemco	Liquid Level	HEADLEY 9-33	1
Cemco	Liquid Level	GUN CLUB UPRR 31-3 2	1
Cemco	Liquid Level	GUN CLUB 16-34 - GUN CLUB 9-34	1
Cemco	Liquid Level	CARNEY 15-34 - KEMPER 10-34	1
Cemco	Liquid Level	CASSEDAY 42-12 1	1
Cemco	Liquid Level	FRICO 10-10 - FRICO 15-10	1
Cemco	Liquid Level	CRAVEN 33-22 - MOSIER 1	1
Cemco	Liquid Level	DANE 9-10 - FRICO 16-10	1
Cemco	Liquid Level	DAN 11-22 - WHITNEY 1-22	1
Cemco	Liquid Level	WEEKS 10-17 - WEEKS 9-17	1
Cemco	Liquid Level	WASTE SERVICES 4-34 - WASTE SERVICES 5-34	1
Cemco	Liquid Level	WASTE SERVICES 16-26 - WASTE SERVICES 9-26	1
Cemco	Liquid Level	WASTE SERVICES 10-26 - WASTE SERVICES 15-26	1
Cemco	Liquid Level	ALBERSTEIN 16-23 - ASHLEY 15-23A	1
Cemco	Liquid Level	UPRR 22 PAN AM U 2	1
Cemco	Liquid Level	ALVIN DECHANT 12-8 - ALVIN DECHANT 13-8	1
Cemco	Liquid Level	UPRC 29-4J - UPRC 29-5J	1
Cemco	Liquid Level	TIM GITTLEIN 4-9 - TIM GITTLEIN 5-9	1
Cemco	Liquid Level	SHELTON 42-2 - SHELTON 7-2	1
Cemco	Liquid Level	ATKINSON 6-31 - SANTIAGO 5-31	1
Cemco	Liquid Level	SHELTON 17-2 - SHELTON 31-2	1
Cemco	Liquid Level	AUGUST 15-29 - AUGUST 16-29	1
Cemco	Liquid Level	SARCHET 2-24 - TRAURIG 1-24	1
Cemco	Liquid Level	RITCHEY 1-27 1	1
Cemco	Liquid Level	BENIRSCHKE 10-23 - GRASSHOPPER 9-23	1
Cemco	Liquid Level	PETERSON 12-29 - RAININ 13-29	1
Cemco	Liquid Level	PANTALEO 10-29A	1
Cemco	Liquid Level	MORALES 7-19 - OSBORNE 8-19A	1
Cemco	Liquid Level	MOORE UPRC H 28-12 - MOORE UPRC H 28-13	1
Cemco	Liquid Level	BOST 12-11 - LIBBY 11-11	1
Cemco	Liquid Level	MASCHMEYER 15-30 - MULBERG 16-30	1
Cemco	Liquid Level	LDS B 5-17 - LDS B 6-17	1
Cemco	Liquid Level	LDS A 4-8 - LDS A 5-8	1
Cemco	Liquid Level	LDS A 3-8 - LDS A 6-8	1
Cemco	Liquid Level	LDS A 16-8 - LDS A 9-8	1
Cemco	Liquid Level	LDS A 11-8 - LDS A 14-8	1
Cemco	Liquid Level	LDS A 10-8 - LDS A 15-8	1
Cemco	Liquid Level	BRUTSCHY 4-24 - HOFFMAN 3-24	1
Cemco	Liquid Level	CALIENTE 16-11 - GULICK 15-11	1
Cemco	Liquid Level	KATE 13-11 - NICHOLAS 14-11	1
Cemco	Liquid Level	JEPSEN 23-2	1
Cemco	Liquid Level	JEPSEN 22-2	1
Cemco	Liquid Level	JEPSEN 2	1
Cemco	Liquid Level	JEPSEN 11-2 - JEPSEN 21-2	1
Cemco	Liquid Level	IAN 13-20 - WARDELL JJ B 1	1
Cemco	Liquid Level	HOUSE 3-20 - HOUSE 6-20	1

High-Bleed Devices – D-J Basin			
Style	**Service**	**Location / Facility Name**	**Number of Devices**
Cemco	Liquid Level	CANNON 3-28 1	1
Cemco	Liquid Level	HARTMAN 4-1 - KOSKELA 5-1 - LAURICE 6-1	1
Cemco	Liquid Level	GUTTERSEN-STATE 4-14 - GUTTERSEN-STATE 5-14	1
Cemco	Liquid Level	GUTTERSENSTATE 15-28	1
Cemco	Liquid Level	GUTTERSENSTATE 10-28	1
Cemco	Liquid Level	GUTTERSEN B 4-21 - GUTTERSEN B 5-21	1
Cemco	Liquid Level	GUTTERSEN B 3-21 - GUTTERSEN B 6-21	1
Cemco	Liquid Level	GUTTERSEN A 16-3 - GUTTERSEN A 9-3	1
Cemco	Liquid Level	GUTTERSEN A 10-3 - GUTTERSEN A 15-3	1
Cemco	Liquid Level	GUTTERSEN 3-4 - GUTTERSEN 5-4 - MELVIN Y 4-4	1
Cemco	Liquid Level	GUTTERSEN 3-33 - GUTTERSEN 6-33	1
Cemco	Liquid Level	GUTTERSEN 3-15 - GUTTERSEN 6-15 - MILLS UPRC D 15-4	1
Cemco	Liquid Level	GUTTERSEN 15-1 - GUTTERSEN 16-1	1
Cemco	Liquid Level	GUTTERSEN 1-4 - GUTTERSEN 2-4 - GUTTERSEN 7-4	1
Cemco	Liquid Level	GUTTERSEN 12-33 - GUTTERSEN 13-33	1
Cemco	Liquid Level	GUTTERSEN 11-33 - GUTTERSEN 14-33	1
Cemco	Liquid Level	GUTTERSEN 11-1 - GUTTERSEN 12-1	1
Cemco	Liquid Level	GREGORY 10-30X - PARAS 9-30 - WESTERN 16-30	1
Cemco	Liquid Level	GITTLEIN, L 3-3 - GITTLEIN, L 6-3	1
Cemco	Liquid Level	GITTLEIN, D 4-3 - GITTLEIN, D 5-3	1
Cemco	Liquid Level	CASTLEMAN 2-31 - TOO DEVINE 1-31	1
Cemco	Liquid Level	FRICO 1-22 - FRICO 8-22	1
Cemco	Liquid Level	FRANK UPRR 43-21 4	1
Cemco	Liquid Level	FRANK UPRR 41-21	1
Cemco	Liquid Level	FRANK UPRR 31-21 1	1
Cemco	Liquid Level	FOSTER 4-35 - FOSTER 5-35	1
Cemco	Liquid Level	COHN 3-25 - CROWE 6-25 - UPRR 53 PAN AM T 2	1
Cemco	Liquid Level	EGGLER 11-29 - EGGLER 14-29	1
Cemco	Liquid Level	EACHUS 4-23 - EACHUS 5-23	1
Cemco	Liquid Level	EACHUS 3-23 - FRUMAN 6-23	1
Cemco	Liquid Level	DUNCAN D 11-7	1
Cemco	Liquid Level	DUNCAN D 11-11 - DUNCAN D 11-6	1
Cemco	Liquid Level	DEMEULES 9-22 - DODGE 10-22	1
Cemco	Liquid Level	DECHANT STATE 7-36 - DECHANT STATE 8-36	1
Cemco	Liquid Level	DECHANT STATE 1-36 - DECHANT STATE 2-36	1
Cemco	Liquid Level	DECHANT FARMS 10-36 - DECHANT FARMS 9-36	1
Cemco	Liquid Level	DECHANT 4-25 - DECHANT 5-25	1
Cemco	Liquid Level	CULLEN 10-11 - PORTER 9-11	1
Cemco	Liquid Level	DALBEY D 25-5	1
Cemco	Liquid Level	DALBEY D 14-3 - DALBEY D 14-6	1
Cemco	Liquid Level	DALBEY D 14-2	1

APPENDIX I

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation,

KERR-MCGEE MANAGEMENT DIRECTIVE REGARDING LOW-BLEED PNEUMATIC CONTROLLERS IN NEW CONSTRUCTION

KerrMcGee

JAMES J. KLECKNER
VICE PRESIDENT

Kerr-McGee Oil & Gas Onshore LP
1999 BROADWAY, SUITE 3700
303-296-3600 FAX. 303-296-3601
E-MAIL: jim.kleckner@anadarko.com

February 15, 2007

Pat Wienke
Supply Chain Supervisor
1999 Broadway, Suite 3700
Denver, CO 80202

Re: ***Management Directive Regarding the Purchase of Pneumatic Controllers at All Newly Constructed Facilities in the DJ and Uinta Basins***

Dear Pat:

From this date forward, it will be the policy of Kerr-McGee Oil & Gas Onshore LP, a wholly-owned subsidiary of Anadarko Petroleum Corporation, to use low-bleed pneumatic controllers to reduce emissions of natural gas at all newly constructed facilities in the DJ and Uinta Basins, to the extent practical where instrument air is not available.

If anyone believes that it will not be practical to use low-bleed pneumatic controllers in any new construction, approval must be obtained from the Environmental, Health and Safety group before proceeding in a matter contrary to this Management Directive.

Very truly yours,

Jim Kleckner
Vice President

cc: Alan Williams, APC EH&S Rockies
Don Anderson, APC EH&S Midstream
Richard Waters, APC Legal
David Howell, APC DJ
Scott Hagemann, APC Uinta
Rick Jones, APC, Mgr. Supply Chain
Dave Keanini, APC Midstream Engineering
Rex Specht, APC Midstream Operations
Phillip Schlagel, APC EH&S Rockies

APPENDIX J

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation,

EMISSION CALCULATION METHODOLOGY FOR THE FORT LUPTON FACILITY

Overview and Purpose

Kerr-McGee has agreed to comply with a consolidated annual VOC emission limit for equipment leaks from components at the Fort Lupton Facility as part of the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). As required in the Consent Decree at Section IV.D., Kerr-McGee will calculate VOC emissions using the following calculation:

> No. of Components x EF (lbs/component-hr) x 8760 hrs/yr x weight % VOC in gas stream x (1-control effectiveness). Total Fugitive VOC emissions will be the sum of emissions for each type of component.

Emission Factors

Appropriate Emission Factors for individual types of components in lbs/component-hr (from Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Table 2-4). Gas service factors listed below:

Connectors = 0.00044
Flanges = 0.000858
Open-ended Line = 0.0044
*Other = 0.01936
Pump = 0.00528
Valve = 0.0099
* This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps or valves.

Control Effectiveness

The source is allowed to use the following control efficiencies (for only the equipment type and service referenced) so long as the source is complying with the LDAR requirements of 40 CFR Part 60, Subpart KKK (EPA-453/R-95-017, Table 5-3):

Equipment Type and Service	Control Effectiveness (%)
Valves – gas	70
Valves – light liquid	61

Pumps – light liquid	45

No. of Components

The number of components shall be based on the most recent component count conducted at the facility.

VOC Content

VOC content of a gas stream shall be determined by the most recent gas analysis.

APPENDIX K

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation,

SCOPE OF WORK FOR THE FEASIBILITY STUDY OF THE MULTI-PHASE PIPING/TANKLESS WELL-SITE PILOT PROJECT

FORERUNNER
CORPORATION

Scope of Work for the Feasibility Study of the Multi-Phase Piping/TanklessWellsite Pilot Project

Prepared For:

Kerr-McGee Corporation

Prepared By:

FORERUNNER CORPORATION
3900 S. Wadsworth Blvd., #600
Lakewood, Colorado 80235

April 26, 2007

Table of Contents

I. Introduction

This Scope of Work ("SOW") describes a study of the technical and operational feasibility ("Study") of a proposed Multi-Phase Piping/Tankless Wellsite Pilot Project Feasibility Study ("Multi-Phase Pilot") to be implemented by Kerr-McGee Oil & Gas Onshore LP, Westport Field Services LLC and/or certain of their corporate affiliates ("Kerr-McGee") at a location selected by Kerr-McGee within the Uinta Basin of Utah near other current and planned drill sites of Kerr-McGee. This SOW has been prepared by Forerunner Corporation ("Forerunner") at the request of Kerr-McGee in order to comply with the anticipated terms of a consent decree being negotiated with the United States and the State of Colorado that will resolve certain alleged violations of the Clean Air Act at facilities of Kerr-McGee in the Uinta Basin and in the Denver-Julesberg Basin of Colorado.

The Study shall assess natural gas gathering system methodologies for enabling tankless wellsite gathering and centralized control of flash emissions of VOCs from gathered condensate, and shall recommend designs of optimum efficiency while remaining technically feasible to build and operate responsibly. The range of methods studied will extend from present practices of Kerr-McGee and other operators involving tankless wellsite gathering to other alternatives for single and multiple pipe systems which may provide operating and environmental benefits to the gathering system operator including the elimination of wellhead storage of hydrocarbon liquids and produced water, as well as the elimination or great reduction of emissions of VOCs from condensate storage tanks at a centralized location, consistent with the purpose of the Multi-Phase Pilot to be set forth in the Consent Decree.

II. Controlling Regulations

Exploration is conducted and natural gas gathering and production facilities are built and operated in the Uinta Basin under the auspices of several Federal agencies. Important aspects of the regulations and practices affect the design and operation of gathering systems. These include the Bureau of Land Management (BLM), as administered by the Vernal Field Office, and the Pipeline and Hazardous Materials Safety Administration (PHMSA). The applicable regulations of such agencies may dictate specific design and operational practices which must be employed for protection of the public and the environment, as well as providing for operator safety. The Study will evaluate approaches to tankless wellsite gathering that can comply with such regulations, and may eliminate or fail to recommend approaches which might violate such regulations.

III. System Complexity and Design Conditions

The presently employed well head gathering practice is dependable and of low complexity, consisting largely of dedicated liquid separation and atmospheric storage of liquids at well sites, with natural gas piped at convenient pressure(s) to a central point for further treating. Alternatives exist or can be defined which may improve operability and reduce losses/emissions. Typically, these alternatives require added piping, equipment, *instrumentation and/or controls, thereby increasing system complexity, although options may exist which reduce system complexity for similar performance improvements. The study will evaluate such changes in system complexity for their operational feasibility throughout the anticipated life of the producing wells to be served by the Multi-Phase Pilot.*

A. Information and Data Collection

Several physical, operational, and technical constraints will shape the design of the system. Critical data for this evaluation is summarized below, and includes but is not limited to all physical well and well field data, local topography, well/wellfield surface and mineral ownership, local population density, local soils and water resources sensitivity, etc. In addition, the impact of incorporating guidance from federal regulatory agencies must be evaluated, as noted above.

1. *Mineral Ownership - Measurement and Royalty Payment Basis*

   Ownership of mineral interests may vary by well throughout a production field. Production must be accurately measured to ensure proper royalty payments.

2. *Surface Access and Rights of Way (ROWs)*

   Agreements must be reached with landowners to permit access for exploration and operation.

3. *Specific Well Data (existing and projected)*

   Specific information from each well will have a significant impact on the design requirements of the complete system. Information related to the initial production rates, operating pressures, hydrocarbon composition and the projected life of the well must be evaluated, to the extent available. Use of data from other producing wells in close proximity to the proposed location of the Multi-Phase Pilot shall also be considered.

4. *Wellfield Area Data*

   Physical information concerning the project area will need to be evaluated. Significant changes in elevation and temperature can drastically affect the requirements of a multi-phase system. Historic regional data will be evaluated and incorporated into the project design.

5. *Liquids: Freezing and/or Hydrates Formation*

   Initial information indicates that use of surface pipelines is the current practice in this area. Utilizing this practice exposes pipe and surface equipment to ambient conditions, and specifically freezing conditions in winter months. True multi-phase piping consisting of liquid and gaseous hydrocarbons and water in a single pipeline operating on the ground surface under these conditions can lead to chemical complexes within the piping that may form complete blockages which are difficult, at *best, to free. This important operational challenge will be fully evaluated during the Study.*

6. *Geotechnical Information: Soils Characterization, Aboveground (AG) and Underground (UG) Obstacles*

   Knowledge of the soils present is used to design proper foundations, to support equipment loads, system components and roads, as well as to properly contain and manage production and storm water. Obstacles on and below surface can complicate system design and operation, and will therefore be evaluated as part of the Study.

7. *Past Practice and/or Literature Search*

   Variations of the concepts which may be developed in the Study may have already been tried. To the extent information on the prior application of such concepts is available, it can be used to improve conceptual systems and/or provide real world insight as to what may or may not work well in practice, as opposed to theory. Permit requirements and other regulatory documentation will also be reviewed to develop awareness of elements which may be limiting for new practices.

B. Environmental Impacts

Environmental impacts from condensate storage at oil and gas well head operations will be considered in the Study. Design of the system and construction process may be modified to minimize these effects in accordance with regional best management practices or conditions of approval from regulatory agencies. Among the potential environmental impacts to be evaluated are the following:

* *Surface disturbance*
* *Air Quality*
* *Dust*
* *Local occupied structures and/or human activities density*
* *Unusually Sensitive Areas (water quality)*
* *Threatened and Endangered Species*
* *Noise*
* *Cultural, paleontological and archeological resources*

C. Limiting Conditions

Once data collection is complete, an assessment will be made to identify any situations which may preclude some options for the System. It is important to insure that a specific condition or combination does not exist which could affect the operational feasibility of one or more Systems configurations/approaches to be evaluated.

IV. System Design Steps

System design requires knowledge, to the extent possible, of each well's production characteristics, well field features and the environment in which the system will reside. This information must be collected and analyzed to enable the complete assessment for system selection and design. A range of systems are then developed and assessed to determine the solution that best meets the intended purpose of the Multi-Phase Pilot while also meeting various operating and regulatory limits that may exist. The resulting system must be as simple and reliable to operate and maintain as possible, for the anticipated operating life of the wells to be served, while minimizing environmental impacts.

A. Well Evaluation

Performance data from well(s), including liquids generation and projected well decline, will be evaluated. Information related to incremental production changes such as well addition or intentional flow interruptions must be defined and incorporated.

B. Piping Network

Representative combinations of well production flows will be considered to select piping and equipment sizes to handle the range of production that the system could foreseeably experience. Topographical and geotechnical data for the wellfield and transit areas shall be incorporated. Reasonable worst case and other upset conditions will also be considered to insure the System can accommodate such variations.

C. Receiving Unit

The central collection system(s) must be sized correctly to handle the flows which arrive from the contributing sources. The separation and handling of individual phases must be adequate to achieve sufficient gas quality for downstream processing, while limiting emissions or other product losses to the environment. Where practical, recovery of volatile components is preferred over disposal via combustion methods such as flaring.

D. Modeling Development

The system design is dependent on computer modeling that will simulate the gathering system to be designed. The model(s) employed in the Study will be used to assess the adequacy of various design alternatives early in the design selection phase, and to provide a mechanism to derive the correct pipe, equipment, instrumentation and controls components.

(1) Line Pressure Selection
Line pressures are selected to accommodate the range of operating conditions that the system must accommodate to insure safe and dependable operations.

(2) Product recovery, pigging
All well products must be contained and handled. Gathering system pipe must be regularly cleaned and have accumulated materials removed. Gathering line pigging is the practical method for larger bore pipe, and System design will include provisions for such regular line clearing to prevent and free blockages through pigging.

V. Report and Recommended System

A System will be recommended for demonstration of the steps and rationale used in application of the methods described in the Study. This System shall be comprised of up to 16 Kerr-McGee wells being developed in the Natural Buttes area of northeastern Utah, a rural area in Uintah County, subject to an Incremental Additional Cost Cap specified in Section 8 of the Consent Decree. The recommended System shall be the Subject of a written Report documenting the Study and its conclusions. Economic Feasibility of the recommended System and any possible application of the noted cost cap shall be addressed directly by Kerr-McGee in other written submissions to EPA pursuant to the terms of the noted Consent Decree.

APPENDIX L

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation,

SCOPE OF WORK FOR PERFORMANCE OPTIMIZATION REVIEW

SCOPE OF WORK FOR PERFORMANCE OPTIMIZATION REVIEW

FOR:

KERR-McGEE CORPORATION

April 26, 2007

TABLE OF CONTENTS

1.0 INTRODUCTION

Kerr-McGee (KMG) will be conducting a POR in order to comply with the anticipated terms of a consent decree being negotiated with the United States and the State of Colorado that will resolve certain alleged violations of the Clean Air Act. The project as proposed will follow the requirements as set forth in the consent decree.

KMG is requesting a third party consultant conduct a Performance Optimization Review (POR) at five facilities in the Uinta Basin in Utah and five facilities in the Denver-Julesberg Basin in Colorado. The POR is a newly proposed process that will follow several EPA Natural Gas STAR Program practices and technologies with the goal of increasing product recovery and reducing or minimizing air emissions. The following scope of work will detail the proposed components of the POR.

2.0 SCOPE OF WORK

The scope will be broken down by proposed facilities included in POR, POR components, and review details as more specifically described below.

2.1 Facilities

The POR is to be conducted at five facilities in the D-J Basin and five facilities in the Uinta Basin. The five facilities in the D-J Basin shall consist of four (4) well-site facilities and (1) compressor station. The five facilities in the Uinta Basin shall consist of four (4) well-site facilities and (1) compressor station.

D-J Basin Facilities:

- Platteville Compressor Station;
- HSR-Stewart 2 & 7-18 (Tank Battery 72810) AIRS ID 1232041001;
- HSR-Tuttle 3, 4, 5, & 6-8 (Tank Batteries 75810 & 75813) AIRS ID 1232032001 & 1232031001;
- Buerger 10-5/Crawford 9-5 (Tank Battery 71210) AIRS ID 1233211001; and
- One new drill to be determined at the time of proposed visit.

Uinta Basin Facilities:

- Morgan State Compressor Station;
- NBU 23;
- NBU 32Y;
- NBU 18M; and
- One new drill to be determined at time of proposed visit.

2.2 POR Components

The items to be addressed in the POR will include the following list.

Pressure Relief Devices - repair or replace components as appropriate to reduce product losses;
Pneumatic Controllers - evaluate for use of low-bleed devices or instrument air;
Production Separators - identify optimal pressures and temperatures;
Dehydrators - evaluate for use of condensers, flares, flash tanks, and electric pumps to reduce natural gas product losses;
Internal Combustion Engines - evaluate maintenance practices and planned shutdown procedures to reduce product losses from blow down and to eliminate use of starter gas as appropriate;
Flare and Vent Systems - evaluate flare and vent system components and associated operating procedures to reduce venting and loss of product where possible;
Producing Wells - install plunger lifts where appropriate and perform "green completion" practices on new wells, as appropriate;
Operating Pressures - review and optimize where possible; and
Component Inspections and Repair - perform component inspections using OVA, TVA, or other leak detection equipment and repair or replace leaking components, as appropriate, to enhance product recovery. For this process a leak is defined by an instrument reading of 10,000 ppm or greater for all components with the exception of pressure relief devices in gas/vapor service which shall have a leak definition of 500 ppm or greater.

2.3 Review Details

Each site will be visited by the same group of individuals to verify consistency throughout the process. Once at a site a site walk through will occur to identify sections of the review that will be applicable to that site. The date, location, and personnel involved will be documented for each site visit. Each component of the POR will be detailed in the following sections.

2.3.1 Pressure Relief Devices will be inspected using OVA, TVA, or other leak detection equipment to determine if any relief devices are leaking. Any leaks found will be repaired or replaced to minimize product losses. Any replacements or repairs that would require a facility shutdown will be put on a shutdown list that will be signed and documented.

A review will be conducted of any company procedures for testing pressure relief devices and documentation of any such reviews. Personnel responsible for any pressure relief device testing will be interviewed. Suggestions for any potential procedural improvements will be provided.

2.3.2 Pneumatic controllers will be evaluated for gas losses. Opportunities for retrofit or replacement of high-bleed controllers will be outlined. Vendors of low-bleed retrofit devices will be relied upon to determine if a device is capable of having a retrofit component added. Upgrading high-bleed controllers could be through use of low or no-bleed controllers, use of instrument air, or other options.

2.3.3 Production separators will be evaluated for optimal operating pressures. Pressures must be sufficient to allow production into the available gathering pipelines and production facilities.

Pressures at compressor stations will be evaluated for optimal operation pressures based on equipment utilized at the station. Process engineers familiar with the particular station under review will be interviewed. The intent is to minimize product losses, if possible, under the physical and operational design of the station.

2.3.4 Dehydrator process reviews will detail any opportunities to reduce or minimize product losses associated with the process. The dehydration process for each facility will be reviewed on the ground rather than from P&IDs. Process variables related to product recovery will be reviewed during the on-site review...to include but not be limited to...glycol circulation rate, flash tank pressure (if applicable), condenser temperature (if applicable), glycol circulation pump and associated control equipment.

2.3.5 Internal combustion engines maintenance practices and shutdown procedures will be reviewed. Opportunities for reducing venting and product loss will be reviewed and discussed with appropriate personnel. Written processes or procedures that are available will be reviewed. Recommendations will be based on what constraints are found at the specific site.

2.3.6 Flare and vent systems will be evaluated and reviewed for options to reduce loss of product. Leak monitoring may include OVA, TVA or equivalent. Review options of flare systems versus vent systems and other reasonable alternatives.

2.3.7 Producing wells will be reviewed for options to reduce any gas losses. Options for review may include plunger lifts and green completion options. Processes for recompletes or reworks will be discussed with appropriate personnel. Opportunities for reduction in gas venting will be documented.

2.3.8 Operating pressures will be evaluated to determine if there are any opportunities to improve product recovery within the current design of the systems in place. This will not include re-engineering any of the current systems. This evaluation may include components as described in section 2.3.3.

2.3.9 Component inspections and repairs will take place at the listed facilities. A reputable leak detection and repair company will be contracted to perform all leak inspections. Any leak discovered will be tagged and appropriate company personnel will be notified of the leaking component for addressing the issue consistent with the Consent Decree requirements as applicable.

3.0 DELIVERABLES

A detailed final report of the reviewed items as listed in the proposed scope of work will be submitted to KMG. The report will include documentation on all review details listed in the scope of work consistent with the Consent Decree requirements. The report will list estimated emission reductions or gas recovered as appropriate and calculation procedures for those estimations. One report will be submitted for each basin.

APPENDIX M

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation

SCOPE OF WORK FOR UINTAH COUNTY ROAD SUPPLEMENTAL ENVIRONMENTAL PROJECT

Overview and Purpose

Kerr-McGee has agreed to implement a Supplemental Environmental Project to improve a county road in Uintah County ("Road Dust SEP") as part the settlement of alleged Clean Air Act violations with the United States and the State of Colorado. The terms of that settlement will be memorialized in a consent decree to be entered by the United States District Court for the District of Colorado to be styled *United States of America and the State of Colorado v. Kerr-McGee Corporation* (hereafter the "Consent Decree"). Kerr-McGee has specifically agreed to provide funds to the Uintah County Road Department to implement the Road Dust SEP.

Introduction

Unpaved roads can be a source of road dust and particulate emissions in Uintah County. The Road Dust SEP will be used to fund part of the paving of a county road in Uintah County.

Timeframe

Kerr-McGee shall implement the Road Dust SEP within 12 months after entry of the Consent Decree.

Project Plan

Kerr-McGee shall implement the Road Dust SEP by providing $100,000 to the Uintah County Road Department. The Uintah County Road Department will use the money to plan, develop and implement a project plan and accomplish the following tasks:

- Identify a portion of a county road in Uintah County to be improved through implementation of the Road Dust SEP;
- Implement the paving project or emission reduction plan; and
- Summarize achievements and submit report to Kerr-McGee.

Specific project criteria will be developed by the Uintah County Road Department to maximize the emission reductions of particulate matter and road dust with the funding to be provided. Emission reductions will be estimated using AP 42 emission factors or other emission estimation methodology, as appropriate.

SEP Completion Report

Kerr-McGee shall request the following information from the Uintah County Road Department within thirty (30) days after the completion of the Road Dust SEP, including 1) a detailed description of the project as implemented; 2) itemized costs, and 3) a description of the environmental and public health benefits resulting from implementation of the project (with quantification of the benefits and pollutant reductions, if feasible). Kerr-McGee shall prepare and submit a SEP Completion Report to EPA within thirty (30) days of receiving the noted information from the Uintah County Road Department.

APPENDIX N

to the

Consent Decree

in the matter of

United States of America and the State of Colorado v. Kerr-McGee Corporation,

SCOPE OF WORK FOR THE ACCELERATED VEHICLE RETIREMENT STATE SEP

Accelerated Vehicle Retirement (AVR) Program
Supplemental Environmental Project (SEP)

Introduction

Older and higher-emitting vehicles disproportionately contribute to the Denver area's air quality problems. This proposed AVR program will be operated by the Regional Air Quality Council (RAQC). The program will be designed to identify and retire older and/or higher-emitting vehicles from Denver area roadways. The RAQC will utilize a number of identification strategies, including but not limited to, remote sensing, Emission Technical Center inspections and Air Care Colorado lane inspections to find candidate vehicles. The goal is to salvage 75 – 200 vehicles.

Candidate vehicles will be retired through participating salvage yards. Emissions control equipment and vehicle engine blocks, along with other specified equipment will be destroyed. An inspection process will be performed to ensure retired equipment is eliminated from operation.

Timeframe

This project will operate through December 31, 2009, unless the Parties and the RAQC agree to a different end date.

Project Plan

The RAQC will develop and implement a project plan addressing the following:

- Vehicle eligibility (including ineligible collectible vehicles);
- Identification protocols;
- Notification protocol;
- Emissions testing protocol;
- Participating salvage yard requirements;
- Salvage process;
- Equipment destruction inspections; and
- Program evaluation

Project criteria will be developed to maximize the emissions reductions of hydrocarbons, carbon monoxide, particulate matter and oxides of nitrogen. Project benefits will be quantified by performing pre-retirement IM240, idle test and/or evaporative emissions testing protocols.

Budget

Program expenditures will categorized into program administration and retirement offers. Program administrative funds will be expended on personnel and notification materials and costs. Potential costs could also include contracting portions of the process out. Program administration expenses shall not exceed $15,000.

Retirement offers will be determined by RAQC analysis. Offers are estimated to range between $1,000 – $3,000 per vehicle.

Project Evaluation

The RAQC shall supply a report to CDPHE within thirty (30) days after the completion of the project containing the following information: 1) a detailed description of the project as implemented; 2) a description of any operating problems encountered and the solutions thereto; 3) itemized costs, documented by copies of purchase orders and receipts or canceled checks; 4) certification that the SEP has been fully implemented pursuant to the provisions of this Consent Decree; and 5) a description of the environmental and public health benefits resulting from implementation of the project (with quantification of the benefits and pollutant reductions, if feasible).