AIR QUALITY

PERMIT TO CONSTRUCT

Permittee	Alta Mesa Services, LP
Permit Number	P-2015.0053
Project ID	61600
Facility ID	075-00026
Facility Location	2.5 Miles NE of the Intersection of Highway 52 & Little Willow Rd. New Plymouth, ID 83661

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules), IDAPA 58.01.01.200–228; (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued DRAFT XX, 2016

Kelli Wetzel, Permit Writer

Mike Simon, Stationary Source Manager

Contents

1 Permit Scope

Purpose

1.1 This is the initial permit to construct (PTC) for an oil and gas production well site known as DJS 1-15.

Regulated Sources

Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 Regulated Sources

Permit Section	Source	Control Equipment
2	Well Head Heater Rated capacity: 0.05 MMBtu/hr Allowable fuel type: natural gas only	None
2	Line Heater Rated capacity: 0.5 MMBtu/hr Allowable fuel type: natural gas only	None
2	Heater Treater Rated capacity: 1.0 MMBtu/hr Allowable fuel type: natural gas only	None
2	10 Oil Tanks Capacity: 500 bbl each	Control Efficiency 95.0%
2	4 Water Tanks Capacity: 80 bbl each	None
2	Oil Loading	Control Efficiency 98.0%
2	Flare Throughput: 1500 scf/day	None (considered an emission control device during an emergency situation)
3	Compressor Engine Max Capacity: 610 bhp Allowable fuel type: natural gas only	None

2 Oil and Gas Production Well Site

2.1 Process Description

The facility is an oil and gas production well site that will be operated for the gathering and processing of produced hydrocarbons.

Production from this site will flow through separators and line heaters where any free water and natural gas liquids will be collected. Liquids separated for the separators will be sent to onsite tanks for storage where they will be pumped to trucks for disposal. The gas will proceed to a central dehydration unit where the remaining water will be removed from the wet gas stream. The gas will then be compressed with a natural gas engine compressor to be sent to pipeline and moved to the refrigeration plant approximately eight miles to the south.

2.2 Control Device Descriptions

Table 2.1 Oil and Gas Production Well Site Description

Emissions Units / Processes	Control Devices
Well Head Heater	None
Line Heater	None
Heater Treater	None
10 Oil Tanks	None
4 Water Tanks	None
Oil Loading	None
Flare	None

Emission Limits

2.3 Emission Limit

The permittee shall not discharge to the atmosphere from any fuel burning equipment with a maximum rated input of ten million BTU per hour or more, PM in excess of 0.015 gr/dscf corrected to 3% oxygen, in accordance with IDAPA 58.01.01.676-677.

2.4 Opacity Limit

Emissions from the any stack, vent, or functionally equivalent opening shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

2.5 Flare Particulate Matter Emission Limit

Particulate matter (PM) emissions from the flare shall not exceed 0.2 pounds per 100 pounds of fuel burned, as required by IDAPA 58.01.01.785.

Operating Requirements

2.6 Fuel Type Restriction

All fuel burning equipment listed in Table 2.1 shall be fired on natural gas exclusively.

2.7 Flare Pilot Flame

A pilot flame must be present at the flare.

2.8 Reasonable Control of Fugitive Emissions

All reasonable precautions shall be taken to prevent particulate matter (PM) from becoming airborne in accordance with IDAPA 58.01.01.650-651. In determining what is reasonable, considerations will be given to factors such as the proximity of dust-emitting operations to human habitations and/or activities and atmospheric conditions that might affect the movement of PM. Some of the reasonable precautions include, but are not limited to, the following:

- Use, where practical, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of lands.
- Application, where practical, of asphalt, oil, water, or suitable chemicals to, or covering of, dirt roads, material stockpiles, and other surfaces which can create dust.
- Installation and use, where practical, of hoods, fans, and fabric filters or equivalent systems to enclose and vent the handling of dusty materials. Adequate containment methods should be employed during sandblasting or other operations.
- Covering, where practical, of open-bodied trucks transporting materials likely to give rise to airborne dusts. Paving of roadways and their maintenance in a clean condition, where practical.
- Prompt removal of earth or other stored material from streets, where practical.

Monitoring and Recordkeeping Requirements

2.9 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

a) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

b) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee’s assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

2.10 Responsible Control Measures

The permittee shall conduct a quarterly facility-wide inspection of potential sources of fugitive emissions, during daylight hours and under normal operating conditions, to ensure that the methods used to reasonably control fugitive emissions are effective. If fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive emissions inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed), any corrective action taken in response to the fugitive emissions, and the date the corrective action was taken. A compilation of the most recent five years of records shall be kept onsite and made available to DEQ representatives upon request.

Federal Requirements

40 CFR 60 Subpart OOOO Requirements

"Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution"

2.11 In accordance with 40 CFR 60.5370, the permittee must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

2.12 In accordance with 40 CFR 60.5400(a), the permittee must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401 for the group of all equipment, except compressors, within a process unit.

2.13 In accordance with 40 CFR 60.482-1a(a), the permittee must demonstrate compliance with the requirements of §§60.482-1a through 60.482-10a or §60.480a(e) for all equipment within 180 days of initial startup.

2.14 In accordance with 40 CFR 60.482-1a(b), compliance will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

2.15 In accordance with 40 CFR 60.482-1a(d), equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in §60.486a(e)(5).

2.16 In accordance with 40 CFR 60.482-2a(a)(1), each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

2.17 In accordance with 40 CFR 60.482-2a(a)(2), each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482-1a(f).

2.18 In accordance with 40 CFR 60.482-2a(b)(1), the instrument reading that defines a leak is specified below:

- 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- 2,000 ppm or greater for all other pumps.

2.19 In accordance with 40 CFR 60.482-2a(b)(2), if there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure below. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified, whichever is applicable.

- Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak. The leak shall be repaired using the procedures in paragraph (c) of this section.
- Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

2.20 In accordance with 40 CFR 60.482-2a(c)(1), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

2.21 In accordance with 40 CFR 60.482-2a(c)(2), a first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described below, where practicable.

- Tightening the packing gland nuts;
- Ensuring that the seal flush is operating at design pressure and temperature.

2.22 In accordance with 40 CFR 60.482-2a(d), each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified below are met.

- Each dual mechanical seal system is:
    - Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
    - Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10a; or
    - Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- The barrier fluid system is in heavy liquid service or is not in VOC service.
- Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
- Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
    - If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.
        - Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
        - Designate the visual indications of liquids dripping as a leak.

- Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.
  - The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
  - If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.
- When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.
  - A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
  - A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

2.23 In accordance with 40 CFR 60.482-2a(e), any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

- Has no externally actuated shaft penetrating the pump housing;
- Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and
- Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.24 In accordance with 40 CFR 60.482-2a(f), if any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

2.25 In accordance with 40 CFR 60.482-2a(g), any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

- The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and
- The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

2.26 In accordance with 40 CFR 60.482-2a(h), any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

2.27 In accordance with 40 CFR 60.482-4a(a), except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

2.28 In accordance with 40 CFR 60.482-4a(b), after each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9a.

- No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

2.29 In accordance with 40 CFR 60.482-4a(c), any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.

2.30 In accordance with 40 CFR 60.482-4a(d), any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements below.

- After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482-9a.

2.31 In accordance with 40 CFR 60.482-5a(a), each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482-1a(c) and paragraph (c) of this section.

2.32 In accordance with 40 CFR 60.482-5a(b), each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified below.

- Gases displaced during filling of the sample container are not required to be collected or captured.
- Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
- Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
- Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph below.
    - Return the purged process fluid directly to the process line.
    - Collect and recycle the purged process fluid to a process.
    - Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10a.
    - Collect, store, and transport the purged process fluid to any of the following systems or facilities:

- A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;
- A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;
- A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;
- A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or
- A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

2.33 In accordance with 40 CFR 60.482-5a(c), in-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

2.34 In accordance with 40 CFR 60.482-6a(a), each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1a(c) and paragraphs (d) and (e) of this section.

- The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

2.35 In accordance with 40 CFR 60.482-6a(b), each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

2.36 In accordance with 40 CFR 60.482-6a(c), when a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

2.37 In accordance with 40 CFR 60.482-6a(d), open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

2.38 In accordance with 40 CFR 60.482-6a(e), open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

2.39 In accordance with 40 CFR 60.482-7a(a), each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g),and (h) of this section, §60.482-1a(c) and (f), and §§60.483-1a and 60.483-2a.

- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1a(c), and §§60.483-1a and 60.483-2a.
    - Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
    - If the existing valves in the process unit are monitored in accordance with §60.483-1a or §60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

2.40 In accordance with 40 CFR 60.482-7a(b), if an instrument reading of 500 ppm or greater is measured, a leak is detected.

2.41 In accordance with 40 CFR 60.482-7a(c), any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

- As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.
- If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

2.42 In accordance with 40 CFR 60.482-7a(d), when a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9a.

- A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.43 In accordance with 40 CFR 60.482-7a(e), first attempts at repair include, but are not limited to, the following best practices where practicable:

- Tightening of bonnet bolts;
- Replacement of bonnet bolts;
- Tightening of packing gland nuts;
- Injection of lubricant into lubricated packing.

2.44 In accordance with 40 CFR 60.482-7a(f), any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- Has no external actuating mechanism in contact with the process fluid,
- Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

- Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

2.45 In accordance with 40 CFR 60.482-7a(g), any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

2.46 In accordance with 40 CFR 60.482-7a(h), any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
- The process unit within which the valve is located either:
    - Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or
    - Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.
- The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

2.47 In accordance with 40 CFR 60.482-8a(a), if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

- The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.
- The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

2.48 In accordance with 40 CFR 60.482-8a(b), if an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

2.49 In accordance with 40 CFR 60.482-8a(c), when a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a.

- The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

2.50 In accordance with 40 CFR 60.482-8a(d), first attempts at repair include, but are not limited to, the best practices described under §§60.482-2a(c)(2) and 60.482-7a(e).

2.51 In accordance with 40 CFR 60.482-9a(a), delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

2.52 In accordance with 40 CFR 60.482-9a(b), delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

2.53 In accordance with 40 CFR 60.482-9a(c), delay of repair for valves and connectors will be allowed if:

- The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and
- When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.

2.54 In accordance with 40 CFR 60.482-9a(d), delay of repair for pumps will be allowed if:

- Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
- Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

2.55 In accordance with 40 CFR 60.482-9a(e), delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

2.56 In accordance with 40 CFR 60.482-9a(f), when delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

2.57 In accordance with 40 CFR 60.482-10a(a), owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

2.58 In accordance with 40 CFR 60.482-10a(b), vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

2.59 In accordance with 40 CFR 60.482-10a(c), enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

2.60 In accordance with 40 CFR 60.482-10a(d), flares used to comply with this subpart shall comply with the requirements of §60.18.

2.61 In accordance with 40 CFR 60.18(c)(1), flares shall 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.

2.62 In accordance with 40 CFR 60.18(c)(2), flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

2.63 In accordance with 40 CFR 60.18(c)(3), the permittee 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) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

- 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:

  $V_{max} = (X_{H2}-K_1)* K_2$

  Where:

  V_{max} = Maximum permitted velocity, m/sec.

  K_1 = Constant, 6.0 volume-percent hydrogen.

  K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

  X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

- The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

- 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.

2.64 In accordance with 40 CFR 60.18(c)(4), steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

- Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).
- Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

2.65 In accordance with 40 CFR 60.18(c)(5), 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).

2.66 In accordance with 40 CFR 60.18(c)(6), flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

2.67 In accordance with 40 CFR 60.18(d), 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.

2.68 In accordance with 40 CFR 60.18(e), flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

2.69 In accordance with 40 CFR 60.18(f)(1), Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

2.70 In accordance with 40 CFR 60.18(f)(2), the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

2.71 In accordance with 40 CFR 60.18(f)(3), the net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

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

K = Constant, $1.740 \times 10^{-7} \left(\frac{1}{ppm}\right) \left(\frac{g\ mole}{scm}\right) \left(\frac{MJ}{kcal}\right)$

where the standard temperature for $\left(\frac{g\ mole}{scm}\right)$ 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 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

2.72 In accordance with 40 CFR 60.18(f)(4), 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.

2.73 In accordance with 40 CFR 60.18(f)(5), the maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$Log_{10} (V_{max})=(H_T+28.8)/31.7$

V_{max} = Maximum permitted velocity, M/sec

28.8=Constant

31.7=Constant

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

2.74 In accordance with 40 CFR 60.18(f)(6), the maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$V_{max} = 8.706+0.7084 (H_T)$

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).

2.75 In accordance with 40 CFR 60.482-10a(e), owners or operators of control devices 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.

2.76 In accordance with 40 CFR 60.482-10a(f), except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

- If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements below:
  - Conduct an initial inspection according to the procedures in §60.485a(b); and
  - Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.
- If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:
  - Conduct an initial inspection according to the procedures in §60.485a(b); and
  - Conduct annual inspections according to the procedures in §60.485a(b).

2.77 In accordance with 40 CFR 60.482-10a(g), leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

- A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
- Repair shall be completed no later than 15 calendar days after the leak is detected.

2.78 In accordance with 40 CFR 60.482-10a(h), delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

2.79 In accordance with 40 CFR 60.482-10a(i), if a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

2.80 In accordance with 40 CFR 60.482-10a(j), any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

- The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and
- The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

2.81 In accordance with 40 CFR 60.482-10a(k), any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified below:

- The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
- The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
- The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

2.82 In accordance with 40 CFR 60.482-10a(l), the permittee shall record the information specified in below.

- Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
- Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
- For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).
- For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

2.83 In accordance with 40 CFR 60.482-10a(m), closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

2.84 In accordance with 40 CFR 60.482-11a(a), the permittee shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

2.85 In accordance with 40 CFR 60.482-11a(b), except as allowed in §60.482-1a(c), §60.482-10a, or as specified in paragraph (e) of this section, the permittee shall monitor all connectors in gas and vapor and light liquid service as specified below.

- The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).
- If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

- The permittee shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.
    - If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
    - If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
    - If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.
        - The permittee shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
        - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.
        - If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.
    - If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
    - The permittee shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

2.86 In accordance with 40 CFR 60.482-11a(c), for use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

2.87 In accordance with 40 CFR 60.482-11a(d), when a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

2.88 In accordance with 40 CFR 60.482-11a(e), any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

- The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and
- The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

2.89 In accordance with 40 CFR 60.482-11a(f), inaccessible, ceramic, or ceramic-lined connectors. (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

- Buried;
- Insulated in a manner that prevents access to the connector by a monitor probe;
- Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
- Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;
- Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
- Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

- If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

2.90 In accordance with 40 CFR 60.482-11a(g), except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

2.91 In accordance with 40 CFR 60.5400(b), the permittee may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

2.92 In accordance with 40 CFR 60.483-1a(a), the permittee may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

2.93 In accordance with 40 CFR 60.483-1a(b), the following requirements shall be met if the permittee wishes to comply with an allowable percentage of valves leaking:

- An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).
- A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.
- If a valve leak is detected, it shall be repaired in accordance with §60.482-7a(d) and (e).

2.94 In accordance with 40 CFR 60.483-1a(c), performance tests shall be conducted in the following manner:

- All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).
- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

2.95 In accordance with 40 CFR 60.483-1a(d), owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

2.96 In accordance with 40 CFR 60.483-2a(a), the permittee may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

- An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

2.97 In accordance with 40 CFR 60.483-2a(b), the permittee shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7a.

- After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

- After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7a but can again elect to use this section.
- The percent of valves leaking shall be determined as described in §60.485a(h).
- The permittee must keep a record of the percent of valves found leaking during each leak detection period.
- A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

2.98 In accordance with 40 CFR 60.5400(c), the permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

2.99 In accordance with 40 CFR 60.5400(d), the permittee must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

2.100 In accordance with 40 CFR 60.485(a)(a), in conducting the performance tests required in §60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

2.101 In accordance with 40 CFR 60.485(a)(b), the permittee shall determine compliance with the standards in §§60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

- Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:
  - Zero air (less than 10 ppm of hydrocarbon in air); and
  - A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.
- A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except donot adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration

drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.102 In accordance with 40 CFR 60.485(a)(c), the permittee shall determine compliance with the no-detectable-emission standards in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

- The requirements of paragraph (b) shall apply.
- Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

2.103 In accordance with 40 CFR 60.485(a)(d), the permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

- Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
- Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.
- Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

2.104 In accordance with 40 CFR 60.485(a)(e), the permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

- The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.
- The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.
- The fluid is a liquid at operating conditions.

2.105 In accordance with 40 CFR 60.485(a)(f), samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

2.106 In accordance with 40 CFR 60.485(a)(h), the permittee shall determine compliance with §60.483-1a or §60.483-2a as follows:

- The percent of valves leaking shall be determined using the following equation:
  $\%V_L = (V_L / V_T) * 100$

  Where:

  $\%V_L$ = Percent leaking valves.

  V_L = Number of valves found leaking.

  V_T = The sum of the total number of valves monitored.

- The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
- The number of valves leaking shall include valves for which repair has been delayed.
- Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
- If the process unit has been subdivided in accordance with §60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
- The total number of valves monitored does not include a valve monitored to verify repair.

2.107 In accordance with 40 CFR 60.5400(e), the permittee must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

2.108 In accordance with 40 CFR 60.486(a)(a), each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

- An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
- The permittee shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
  - Monitoring instrument identification.
  - Operator identification.
  - Equipment identification.
  - Date of monitoring.
  - Instrument reading.

2.109 In accordance with 40 CFR 60.486(a)(b), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

- A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.
- The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
- The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

2.110 In accordance with 40 CFR 60.486(a)(c), when each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

- The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.
- The date the leak was detected and the dates of each attempt to repair the leak.
- Repair methods applied in each attempt to repair the leak.
- Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
- “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
- The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
- The expected date of successful repair of the leak if a leak is not repaired within 15 days.
- Dates of process unit shutdowns that occur while the equipment is unrepaired.
- The date of successful repair of the leak.

2.111 In accordance with 40 CFR 60.486(a)(d), the following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10a shall be recorded and kept in a readily accessible location:

- Detailed schematics, design specifications, and piping and instrumentation diagrams.
- The dates and descriptions of any changes in the design specifications.
- A description of the parameter or parameters monitored, as required in §60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.
- Periods when the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
- Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

2.112 In accordance with 40 CFR 60.486(a)(e), the following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for equipment subject to the requirements of this subpart.
- A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
    - The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.
- A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.

- The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
    - The background level measured during each compliance test.
    - The maximum instrument reading measured at the equipment during each compliance test.
- A list of identification numbers for equipment in vacuum service.
- A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).
    - Date of calibration and initials of operator performing the calibration.
    - Calibration gas cylinder identification, certification date, and certified concentration.
    - Instrument scale(s) used.
    - A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.
    - Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
    - If an owner or operator makes their own calibration gas, a description of the procedure used.
- The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).
- Records of each release from a pressure relief device subject to §60.482-4a.

2.113 In accordance with 40 CFR 60.486(a)(f), the following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

- A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.
- A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

2.114 In accordance with 40 CFR 60.486(a)(g), the following information shall be recorded for valves complying with §60.483-2a:

- A schedule of monitoring.
- The percent of valves found leaking during each monitoring period.

2.115 In accordance with 40 CFR 60.486(a)(h), the following information shall be recorded in a log that is kept in a readily accessible location:

- Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and
- Any changes to this criterion and the reasons for the changes.

2.116 In accordance with 40 CFR 60.486(a)(i), the following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

- An analysis demonstrating the design capacity of the affected facility,
- A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
- An analysis demonstrating that equipment is not in VOC service.

2.117 In accordance with 40 CFR 60.486(a)(j), information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

2.118 In accordance with 40 CFR 60.486(a)(k), the provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

2.119 In accordance with 40 CFR 60.487(a)(a), each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

2.120 In accordance with 40 CFR 60.487(a)(b), the initial semiannual report to the Administrator shall include the following information:

- Process unit identification.
- Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.482-7a(f).
- Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f).
- Number of compressors subject to the requirements of §60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3a(i) and those compressors complying with §60.482-3a(h).
- Number of connectors subject to the requirements of §60.482-11a.

2.121 In accordance with 40 CFR 60.487(a)(c), all semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

- Process unit identification.
- For each month during the semiannual reporting period,
    - Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a,
    - Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1),
    - Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

- Number of compressors for which leaks were detected as described in §60.482-3a(f),
- Number of compressors for which leaks were not repaired as required in §60.482-3a(g)(1),
- Number of connectors for which leaks were detected as described in §60.482-11a(b),
- Number of connectors for which leaks were not repaired as required in §60.482-11a(d), and
- The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

- Dates of process unit shutdowns which occurred within the semiannual reporting period.
- Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

2.122 In accordance with 40 CFR 60.487(a)(d), the permittee electing to comply with the provisions of §§60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

2.123 In accordance with 40 CFR 60.487(a)(e), the permittee shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

2.124 In accordance with 40 CFR 60.487(a)(f), the requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

2.125 In accordance with 40 CFR 60.5400(f), the permittee must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

2.126 In accordance with 40 CFR 60.5401(a), the permittee may comply with the following exceptions to the provisions of §60.5400(a) and (b).

2.127 In accordance with 40 CFR 60.5401(b), each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

- If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

- A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

- Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.
  - No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

2.128 In accordance with 40 CFR 60.5401(c), sampling connection systems are exempt from the requirements of §60.482-5a.

2.129 In accordance with 40 CFR 60.5401(d), pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1) and 60.482-7a(a), and paragraph (b)(1) of this section.

2.130 In accordance with 40 CFR 60.5401(f), the permittee may use the following provisions instead of §60.485a(e):

- Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).
- Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

2.131 In accordance with 40 CFR 60.5401(g), the permittee may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

2.132 In accordance with 40 CFR 60.5402(a), if, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

2.133 In accordance with 40 CFR 60.5402(b), any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

2.134 In accordance with 40 CFR 60.5402(c), the Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

2.135 In accordance with 40 CFR 60.5402(d), the Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

- The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.
- If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

2.136 In accordance with 40 CFR 60.5410, the permittee must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for the permittee’s affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

2.137 In accordance with 40 CFR 60.5410(a), to achieve initial compliance with the standards for each well completion operation conducted at the gas well affected facility the permittee must comply with paragraphs below.

- The permittee must submit the notification required in §60.5420(a)(2).
- The permittee must submit the initial annual report for the well affected facility as required in §60.5420(b).
- The permittee must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.
- For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), the permittee may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period.

As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

2.138 In accordance with 40 CFR 60.5410(d), to achieve initial compliance with emission standards for the permittee's pneumatic controller affected facility the permittee must comply with the requirements specified below.

- The permittee must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of the permittee's determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).
- The permittee own or operate a pneumatic controller affected facility located at a natural gas processing plant and the permittee's pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.
- The permittee own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.
- The permittee must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).
- The permittee must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for the permittee's pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).
- The permittee must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

2.139 In accordance with 40 CFR 60.5410(f), for affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.140 In accordance with 40 CFR 60.5415(a), for each gas well affected facility, the permittee must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

2.141 In accordance with 40 CFR 60.5415(d), for each pneumatic controller affected facility, the permittee must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

- The permittee must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).
- The permittee must submit the annual report as required in §60.5420(b).
- The permittee must maintain records as required in §60.5420(c)(4).

2.142 In accordance with 40 CFR 60.5415(f), for affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if the permittee is in compliance with the requirements of §60.5400.

2.143 In accordance with 40 CFR 60.5415(h), affirmative defense for violations of emission standards during malfunction. In response to an action to enforce the standards set forth in §§60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, the permittee may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at §60.2. Appropriate penalties may be assessed, however, if the permittee fails to meet the burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

- To establish the affirmative defense in any action to enforce such a standard, the permittee must timely meet the reporting requirements in §60.5415(h)(2), and must prove by a preponderance of evidence that:
  - The violation:
    - Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and
    - Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
    - Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
    - Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and
  - Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
  - The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and
  - If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
  - All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and
  - All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and
  - All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and
  - At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and
  - A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

- Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

2.144 In accordance with 40 CFR 60.5420(a), the permittee must submit the notifications according to paragraphs (a)(1) and (2) of this section if the permittee owns or operates one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

- If the permittee owns or operates a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility the permittee is not required to submit the notifications required in §60.7(a)(1), (3), and (4).
- If the permittee owns or operates a gas well affected facility, the permittee must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. The permittee may submit the notification in writing or in electronic format.
    - If the permittee is subject to state regulations that require advance notification of well completions and the permittee has met those notification requirements, then the permittee is considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

2.145 In accordance with 40 CFR 60.5420(b), the permittee must submit annual reports containing the information specified below to the Administrator and performance test reports as specified below. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified below. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

- The general information specified below.
    - The company name and address of the affected facility.
    - An identification of each affected facility being included in the annual report.
    - Beginning and ending dates of the reporting period.

    - A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- For each gas well affected facility, the information below.
    - Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.
    - Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.
- For each pneumatic controller affected facility, the information specified below.
    - An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).
    - If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.
    - Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.
- Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in §60.5413(d), the permittee must submit the results of the performance tests required by this subpart to the EPA as follows. The permittee must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html) existing at the time of the performance test to generate a submission package file, which documents the performance test. The permittee must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the permittee must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

- For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

2.146 In accordance with 40 CFR 60.5420(c), the permittee must maintain the records identified as specified in §60.7(f) and as identified below. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

- The records for each gas well affected facility as specified below.
    - Records identifying each well completion operation for each gas well affected facility;
    - Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.
    - Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. The permittee must maintain the records specified in paragraphs below.
        - For each gas well affected facility required to comply with the requirements of §60.5375(a), the permittee must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.
        - For each gas well affected facility required to comply with the requirements of §60.5375(f), the permittee must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that the permittee does not have to record the duration of recovery to the flow line.
    - For each gas well facility for which the permittee claims an exception under §60.5375(a)(3), the permittee must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.
    - For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if the permittee is using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, the permittee must retain the records of the digital photograph as specified in §60.5410(a)(4).
- For each pneumatic controller affected facility, the permittee must maintain the records identified below.
    - Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

- Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.
- If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.
- If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.
- Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

2.147 In accordance with 40 CFR 60.5421(b), the following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

- When each leak is detected as specified in §60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
- When each leak is detected as specified in §60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:
    - The instrument and operator identification numbers and the equipment identification number.
    - The date the leak was detected and the dates of each attempt to repair the leak.
    - Repair methods applied in each attempt to repair the leak.
    - “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.
    - “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    - The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    - The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    - Dates of process unit shutdowns that occur while the equipment is unrepaired.
    - The date of successful repair of the leak.
    - A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

2.148 In accordance with 40 CFR 60.5422(b), the permittee must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

2.149 In accordance with 40 CFR 60.5422(c), the permittee must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

- Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and
- Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

2.150 NSPS 40 CFR 60 – General Provisions

The permittee shall comply with the requirements of 40 CFR 60, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 2.2 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 60.1	General Applicability of the General Provisions	
40 CFR 60.2	Definitions	Additional terms defined in §60.5430.
40 CFR 60.3	Units and abbreviations	
40 CFR 60.4	Address	
40 CFR 60.5	Determination of construction or modification	
40 CFR 60.6	Review of Plans	
40 CFR 60.7	Notification and record keeping	Except that §60.7 only applies as specified in §60.5420(a).
40 CFR 60.8	Performance tests	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
40 CFR 60.9	Availability of information	
40 CFR 60.10	State authority	
40 CFR 60.12	Circumvention	
40 CFR 60.13	Monitoring requirements	Continuous monitors are required for storage vessels.
40 CFR 60.14	Modification	
40 CFR 60.15	Reconstruction	
40 CFR 60.16	Priority list	
40 CFR 60.17	Incorporations by reference	
40 CFR 60.18	General control device requirements	Except that §60.18 does not apply to flares.
40 CFR 60.19	General notification and reporting requirement	

2.151 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- Standards of Performance for New Stationary Sources (NSPS), 40 CFR Part 60, Subpart OOOO and JJJJ.
- National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT), 40 CFR Part 63, Subpart ZZZZ

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS or NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

3 Compressor Engine

3.1 Process Description

Natural gas is compressed at the facility prior to transport to the refrigeration plant. The compressor will be driven by a 610 bhp Caterpillar natural gas-fired IC engine. The engine manufacture date has not been determined and is subject to 40 CFR 63, Subpart ZZZZ and/or 40 CFR 60 Subpart JJJJ if the engines are manufactured after June 12, 2006.

3.2 Control Device Descriptions

Table 3.1 Compressor Engines Description

Emissions Units / Processes	Control Devices
Compressor Engine 1	None

Emission Limits

3.3 Opacity Limit

Emissions from the Compressor Engine stack, or any other stack, vent, or functionally equivalent opening associated with the compressor engine, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

Operating Requirements

3.4 Fuel Type Restriction

Compressor Engine 1 shall be fired on natural gas exclusively.

Monitoring and Recordkeeping Requirements

3.5 Opacity Monitoring

The permittee shall conduct a quarterly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

c) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

d) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee’s assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Federal Requirements

40 CFR 63 Subpart ZZZZ Requirements

"National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines"

3.6 In accordance with 40 CFR 63.6595(a)(1), the permittee must comply with the applicable emission and operating limitations of the National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ by October 19, 2013 or upon installation.

3.7 In accordance with 40 CFR 63.6603, the permittee shall comply with the requirements in Table 2d to install NSCR (non-selective catalytic reduction) to reduce HAP emissions on Compressor Engine 1.

3.8 In accordance with 40 CFR 63.6605, the permittee shall, at all times, operate and maintain Compressor Engine 1, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

3.9 In accordance with 40 CFR 63.6612, the permittee shall conduct any initial performance test or other initial compliance demonstration according to Table 5 to this subpart within 180 days after the compliance date of October 19, 2013. In order to comply with the requirement to reduce CO and THC emissions, the permittee shall:

- Install NSCR
- Conduct an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more.
- Install a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or install equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

3.10 In accordance with 40 CFR 63.6625(h), the permittee shall minimize Compressor Engine 1's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

3.11 In accordance with 40 CFR 63.6630(e), the permittee shall meet the following requirements to demonstrate initial compliance:

- The compliance demonstration must consist of at least three test runs.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

3.12 In accordance with 40 CFR 63.6635(a), the permittee must monitor and collect data for the Compressor Engine.

3.13 In accordance with 40 CFR 63.6635(b), the permittee must monitor continuously at all times that Compressor Engine 1 is operating except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

3.14 In accordance with 40 CFR 63.6635(c), the permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The permittee must, however, use all the valid data collected during all other periods.

3.15 In accordance with 40 CFR 63.6640(c), the annual compliance demonstration required shall be conducted according to the following requirements:

- The compliance demonstration must consist of at least one test run.
- Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.
- To demonstrate compliance with the CO concentration or CO percent reduction requirement, the permittee must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.
- To demonstrate compliance with the THC percent reduction requirement, the permittee must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.
- The permittee must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.
- To demonstrate compliance with the CO or THC percent reduction requirement, the permittee must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

- If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the permittee demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

3.16 In accordance with 40 CFR 63.6645(a), the permittee shall submit all of the notifications in §§63.7(b) and (c) that apply by the dates specified for Compressor Engine 1.

3.17 In accordance with 40 CFR 63.6645(g), the permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1) for Compressor Engine 1.

3.18 In accordance with 40 CFR 63.6645(h), the permittee shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii) for Compressor Engine 1.

- The permittee shall submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

3.19 In accordance with 40 CFR 63.6650(b), the permittee shall, for semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.6595.

- The permittee shall ensure, for semiannual Compliance reports, that the first Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date.
- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
- The permittee shall ensure, for semiannual Compliance reports, each subsequent Compliance report be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

3.20 In accordance with 40 CFR 63.6650(c), the permittee's Compliance report must contain the following:

- Company name and address.
- Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
- Date of report and beginning and ending dates of the reporting period.
- If a malfunction occurred during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by the permittee during a malfunction to minimize emissions including actions taken to correct a malfunction.

- If there are no deviations from any emission or operating limitations that apply, a statement that there were no deviations from the emission or operating limitations during the reporting period.

3.21 In accordance with 40 CFR 63.6655(a), the permittee shall keep the following records:

- A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that is submitted.
- Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
- Records of performance tests and performance evaluations.
- Records of all required maintenance performed on the air pollution control and monitoring equipment.
- Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

3.22 In accordance with 40 CFR 63.6655(d), the permittee shall keep the records required in Table 6 to this subpart to show compliance with each emission or operating limitation for Compressor Engine 1.

3.23 In accordance with 40 CFR 63.6655 (e), the permittee shall keep the records of the maintenance conducted on the stationary RICE, Compressor Engine 1, in order to demonstrate that the permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's own maintenance plan.

3.24 In accordance with 40 CFR 63.6660(a), the permittee shall keep the records in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

3.25 In accordance with 40 CFR 63.6660(b), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

3.26 In accordance with 40 CFR 63.6660(c), the permittee shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1).

3.27 NESHAPS 40 CFR 63 – General Provisions

The permittee shall comply with the requirements of 40 CFR 63, Subpart A – General Provisions. A summary of applicable requirements for affected facilities is provided in the following table:

Table 3.2 Subpart A – General Provisions

Citation	Subject	Explanation
40 CFR 63.1(a)(1)-(12)	General Applicability	
40 CFR 63.1(b)(1)-(3)	Initial Applicability Determination	Applicability of subpart ZZZZ is also specified in 40 CFR 63.6585
40 CFR 63.1(c)(1)	Applicability After Standard Established	
40 CFR 63.1(c)(2)	Applicability of Permit Program for Area Sources	
40 CFR 63.1(c)(5)	Notifications	
40 CFR 63.2	Definitions	Additional definitions are specified in 40 CFR 63.6675.
40 CFR 63.3(a)–(c)	Units and Abbreviations	
40 CFR 63.4(a)(1)–(5)	Prohibited Activities	
40 CFR 63.4(b)–(c)	Circumvention/Fragmentation	
40 CFR 63.6(a)	Compliance With Standards and Maintenance Requirements—Applicability	
40 CFR 63.6(b)(1)-(7)	Compliance Dates for New and Reconstructed Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(c)(1)-(5)	Compliance Dates for Existing Sources	40 CFR 63.6595 specifies the compliance dates.
40 CFR 63.6(f)(2)-(3)	Methods for Determining Compliance	
40 CFR 63.6(g)(1)-(3)	Use of an Alternative Standard	
40 CFR 63.6(i)(1)-(16)	Extension of Compliance	
40 CFR 63.6(j)	Presidential Compliance Exemption	
40 CFR 63.7(a)(1)-(2)	Performance Test Dates	40 CFR 63.6610-6612 specify the performance test dates
40 CFR 63.7(b)(1)-(2)	Notification of Performance Test and Rescheduling	40 CFR 63.6645 specifies the notification
40 CFR 63.7(e)(2)	Conduct Performance Test and reduction of data	40 CFR 63.6620 specifies appropriate test methods
40 CFR 63.7(g)	Performance Test data analysis and recordkeeping and reporting	
40 CFR 63.8	Monitoring Requirements	40 CFR 63.6625 specifies appropriate monitoring requirements
40 CFR 63.9(a)-(e), (g)-(j)	Notification Requirements	40 CFR 63.645 specifies notification requirements.
40 CFR 63.10(a)	Recordkeeping/Reporting—Applicability and General Information	
40 CFR 63.10(b)(1)	General Recordkeeping Requirements	Additional requirements are specified in 40 CFR 63.6655
40 CFR 63.10(b)(2)(xii)	Waiver of recordkeeping requirements	
40 CFR 63.10(b)(2)(xiv)	Records supporting notifications	
40 CFR 63.10(b)(3)	Recordkeeping Requirements for Applicability Determinations	
40 CFR 63.10(d)(1)	General Reporting Requirements	Additional requirements are specified in 40 CFR 63.6650
40 CFR 63.10(d)(4)	Progress Reports for Sources With Compliance Extensions	
40 CFR 63.10(f)	Recordkeeping/Reporting Waiver	
40 CFR 63.12	State Authority and Delegations	
40 CFR 63.13	Addresses of State Air Pollution Control Agencies and EPA Regional Offices	
40 CFR 63.14	Incorporation by Reference	
40 CFR 63.15	Availability of Information/Confidentiality	

40 CFR 60 Subpart JJJJ Requirements
"Standards of Performance for Stationary Spark Ignition Internal Combustion Engines"

3.28 In accordance with 40 CFR 60.4233, the permittee must comply with the emission standards in Table 1 to this subpart for Compressor Engine 1.

Table 3.3 Table 1 to Subpart JJJJ of Part 60 – NO_x, CO and VOC Emission Standards for Stationary Non-Emergency SI Gas Engines ≥100 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission Standards [a]					
			g/hp-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC [b]	NO_X	CO	VOC [b]
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	hp≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	hp≥500	7/1/2010	1.0	2.0	0.7	82	270	60

a) Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/hp-hr or ppmvd at 15 percent O_2.

b) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

3.29 In accordance with 40 CFR 60.4234, the permittee shall operate and maintain stationary SI ICE that achieve the emission standards as required in 40 CFR 60.4233(e) over the entire life of the engine.

3.30 In accordance with 40 CFR 60.4243(b)(1), if the permittee chooses to purchase a certified engine, the permittee shall purchase an engine certified according to procedures specified in the subpart for the same model year demonstrating compliance to one of the methods specified in paragraph (a) of the section.

3.31 In accordance with 40 CFR 60.4243(b)(2)(ii), if the permittee chooses to purchase a non-certified engine, the permittee shall keep a maintenance plan and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition the permittee must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

3.32 In accordance with 40 CFR 60.4244(a), each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

Table 3.4 Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244.	a. limit the concentration of NO_x in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.
		iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_x concentration.
		v. Measure NO_x at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–	(d) Results of this test consist of the average of	

For each	Complying with the requirement to	You must	Using	According to the following requirements
	stationary internal combustion engine.	00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17).	the three 1-hour or longer runs.	
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.	
	iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.	
	v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A,[c,d] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	

a) ASTM D6522–00 is incorporated by reference; see 40 CFR 60.17. Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

b) You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.

c) You may use EPA Method 18 of 40 CFR part 60, appendix A, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (http://www.epa.gov/ttn/emc/prelim/otm11.pdf).

d) You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.

3.33 In accordance with 40 CFR 60.4244(b), the permittee may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If the stationary SI internal combustion engine is non-operational, the permittee does not need to startup the engine solely to conduct a performance test; however, the permittee must conduct the performance test immediately upon startup of the engine.

3.34 In accordance with 40 CFR 60.4244(c), the permittee must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

3.35 In accordance with 40 CFR 60.4244(d), to determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP - hr} \qquad (Eq.\ 1)$$

Where:

ER = Emission rate of NOX in g/HP-hr.

Cd = Measured NOX concentration in parts per million by volume (ppmv).

1.912×10−3 = Conversion constant for ppm NOX to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

3.36 In accordance with 40 CFR 60.4244(e), to determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \qquad (Eq.\ 2)$$

Where:

ER = Emission rate of CO in g/HP-hr.

Cd = Measured CO concentration in ppmv.

1.164×10−3 = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

3.37 In accordance with 40 CFR 60.4244(f), when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \qquad (Eq.\ 3)$$

Where:

ER = Emission rate of VOC in g/HP-hr.

Cd = VOC concentration measured as propane in ppmv.

1.833×10−3 = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

3.38 In accordance with 40 CFR 60.4244(g), if the permittee chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \qquad \text{(Eq. 4)}$$

Where:

RFi = Response factor of compound i when measured with EPA Method 25A.

CMi = Measured concentration of compound i in ppmv as carbon.

CAi = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \qquad \text{(Eq. 5)}$$

Where:

Cicorr = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

Cimeas = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

CPeq = Concentration of compound i in mg of propane equivalent per DSCM.

3.39 In accordance with 40 CFR 60.4245(a)(1) and (2), the permittee shall keep records of the following information:

- For each engine notifications submitted and all documentation supporting any notification.
- Maintenance conducted on each SI engine.
- If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

The permittee shall maintain these records on-site and be made available to DEQ representatives upon request for a period of at least five years.

3.40 In accordance with 40 CFR 60.4245(c), owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the following information.

- Name and address of the owner or operator;
- The address of the affected source;
- Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
- Emission control equipment; and
- Fuel used.

3.41 In accordance with 40 CFR 60.4245(d), the permittee shall submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed.

3.42 In accordance with 40 CFR 60.4246, the permittee shall comply with the following applicable General Provisions of 40 CFR 60:

Table 3.5 Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

General Provision Citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.
§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

4 General Provisions

General Compliance

4.1 The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the "Rules for the Control of Air Pollution in Idaho." The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit, the "Rules for the Control of Air Pollution in Idaho," and the Environmental Protection and Health Act (Idaho Code §39-101, et seq.)

[Idaho Code §39-101, et seq.]

4.2 The permittee shall at all times (except as provided in the "Rules for the Control of Air Pollution in Idaho") maintain in good working order and operate as efficiently as practicable all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

4.3 Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules, and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

4.4 Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where an emissions source is located, emissions-related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

4.5 This permit shall expire if construction has not begun within two years of its issue date, or if construction is suspended for one year.

[IDAPA 58.01.01.211.02, 5/1/94]

4.6 The permittee shall furnish DEQ written notifications as follows:

- A notification of the date of initiation of construction, within five working days after occurrence; except in the case where pre-permit construction approval has been granted then notification shall be made within five working days after occurrence or within five working days after permit issuance whichever is later;
- A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

- A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date; and
- A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and
- A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211.03, 5/1/94]

Performance Testing

4.7 If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

4.8 All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

4.9 Within 30 days, or up to 60 days when requested following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

4.10 The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Monitoring records shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

Excess Emissions

4.11 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130–136 for excess emissions due to start-up, shut-down, scheduled maintenance, safety measures, upsets, and breakdowns.

[IDAPA 58.01.01.130–136, 4/5/00]

Certification

4.12 All documents submitted to DEQ—including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification—shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

4.13 No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

4.14 No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

4.15 This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

4.16 The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.211, 5/1/94]

Alta Mesa Services

DJS 1-15 Well Site Facility Emission Summary

Source Description		Well Head Heater	Line Heater	Heater Treater	Engine	Water Tanks	Oil Tanks	Loading	Flare	Summary of Emissions
Source Information		0.05 MMbtu/hr	0.5 MMbtu/hr	1.0 MMbtu/hr	Caterpillar G398TA Type Engine - 610 hp	4 Tanks at 80 BWPD (No Control)	10 Tanks at 500 BOPD (95% Control)	500 BOPD (98% Control)	Flare at 100 MSCFD	
EPNs		WHHTR1	LNHTR1	HTRTR1	ENG1	WTRTNK1-4	OILTNK1-10	LOAD1	FLR1	
VOC_{total}	lb/hr	0.0002	0.0022	0.0045	0.6718	0.1448	4.3825	0.6008	0.4227	**6.2295**
	TPY	0.0010	0.0098	0.0196	2.9425	0.6345	19.1960	0.4775	1.8513	**25.1322**
NOx	lb/hr	0.0041	0.0407	0.0813	1.3436				0.3537	**1.8234**
	TPY	0.0178	0.1780	0.3561	5.8850				1.5493	**7.9863**
CO	lb/hr	0.0034	0.0341	0.0683	2.6872				1.6126	**4.4057**
	TPY	0.0150	0.1496	0.2991	11.7700				7.0631	**19.2968**
PM_{10}	lb/hr	0.0003	0.0031	0.0062	0.0924				0.0052	**0.1072**
	TPY	0.0014	0.0135	0.0271	0.4047				0.0228	**0.4694**
$PM_{2.5}$	lb/hr	0.0002	0.0023	0.0046	0.0924				0.0052	**0.1048**
	TPY	0.0010	0.0101	0.0203	0.4047				0.0228	**0.4590**
SO_2	lb/hr	0.00002	0.0002	0.0005	0.0028				0.0052	**0.0088**
	TPY	0.0001	0.0011	0.0021	0.0123				0.0228	**0.0384**
Formaldehyde	lb/hr	3.05E-07	3.05E-06	6.10E-06	0.2514					**0.2514**
	TPY	1.34E-06	1.34E-05	2.67E-05	1.1009					**1.1010**
Benzene	lb/hr	8.54E-08	8.54E-07	1.71E-06	0.0075	0.0001	0.0030	0.0002	0.0002	**0.0110**
	TPY	3.74E-07	3.74E-06	7.48E-06	0.0329	0.0005	0.0130	0.0002	0.0007	**0.0473**
Toluene	lb/hr	1.38E-07	1.38E-06	2.76E-06	0.0027	0.0001	0.0035	0.0002	0.0002	**0.0067**
	TPY	6.05E-07	6.05E-06	1.21E-05	0.0116	0.0005	0.0145	0.0002	0.0007	**0.0276**
Ethylbenzene	lb/hr				0.0002	0.0000	0.0010	0.0001	0.0000	**0.0013**
	TPY				0.0008	0.0001	0.0035	0.0000	0.0002	**0.0047**
Xylene	lb/hr				0.0009	0.0001	0.0025	0.0002	0.0001	**0.0038**
	TPY				0.0041	0.0004	0.0115	0.0001	0.0005	**0.0166**

FUGITIVE EMISSION CALCULATIONS

EPN: FUG1				
Component Type	Gas Component Count	Heavy Oil Component Count	Light Oil Component Count	Water/Light Oil Component Count
Valves	150	25	75	25
Pumps	0	4	0	1
Flanges / Connectors	150	50	100	25
Compressors	1	0	0	0
Relief Lines	3	0	2	2
Open-ended Lines	2	0	0	1
Other	0	0	5	5
Process Drains	5	5	5	5

Component Type	Gas lb/hr per component	Heavy Oil lb/hr per component	Light Oil lb/hr per component	Water/Light Oil lb/hr per component	Gas Emission Rate (lbs/hr)	Heavy Oil Emssion Rate (lbs/hr)	Light Oil Emission Rate (lbs/hr)	Water/ Light Oil Emission Rate (lbs/hr)	Control Efficiency %	Control Efficiency %	Total Emissions lbs/hr	Total Emissions tn/yr
Valves	0.0092	0.00002	0.0055	0.0002	0.3152	0.0005	0.4125	0.0054	0%		0.7336	3.2132
Pumps	0.0053	0.0011	0.0287	0.0001	0.0000	0.0045	0.0000	0.0001	0%		0.0046	0.0200
Flanges / Connectors	0.0009	0.000001	0.0002	0.0000	0.0295	0.000043	0.0243	0.0002	0%	0%	0.0540	0.2364
Compressors	0.0194	0.0001	0.0165	0.0309	0.0044	0.000000	0.0000	0.0000	0%		0.0044	0.0194
Relief Lines	0.0194	0.0001	0.0165	0.0309	0.0133	0.000000	0.0330	0.0618	0%		0.1081	0.4735
Open-ended Lines	0.0044	0.0003	0.0031	0.0006	0.0020	0.000000	0.0000	0.0006	0%		0.0026	0.0115
Other	0.0194	0.0001	0.0165	0.0309	0.0000	0.000000	0.0825	0.1545	0%		0.2370	1.0381
Process Drains	0.0194	0.0001	0.0165	0.0309	0.0222	0.0003	0.0825	0.1545	0%		0.2595	1.1366
Totals											**1.4038**	**6.1486**

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	84.8561	13.613	66.981	**67.0%**		
Nitrogen	28.013	0.4883	0.137	0.673	**0.7%**		
Carbon Dioxide	44.01	0.1433	0.063	0.310	**0.3%**		
Ethane	30.07	6.2131	1.868	9.192	**9.2%**	VOC	
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	**0.0%**	Speciation	
Propane	44.097	4.0209	1.773	8.724	**8.7%**	0.1225	0.5364
Iso-butane	58.124	0.9324	0.542	2.666	**2.7%**	0.0374	0.1640
N-Butane	58.124	1.5751	0.916	4.505	**4.5%**	0.0632	0.2770
Iso-Pentane	72.151	0.5374	0.388	1.908	**1.9%**	0.0268	0.1173
N-Pentane	72.151	0.5433	0.392	1.929	**1.9%**	0.0271	0.1186
N-Hexane	86.07	0.2249	0.194	0.952	**1.0%**	0.0134	0.0586
Cyclohexane	84.16	0.0342	0.029	0.142	**0.1%**	0.0020	0.0087
Heptanes	100.21	0.1201	0.120	0.592	**0.6%**	0.0083	0.0364
Methylcyclohexane	96.17	0.0266	0.026	0.126	**0.1%**	0.0018	0.0077
224-Trimethylpentane	114.22	0.0068	0.008	0.038	**0.0%**	0.0005	0.0023
Benzene	78.11	0.0035	0.003	0.013	**0.0%**	0.0002	0.0008
Toluene	92.14	0.0021	0.002	0.010	**0.0%**	0.0001	0.0006
Ethylbenzene	106.17	0.0003	0.000	0.002	**0.0%**	0.0000	0.0001
Xylenes	106.16	0.0005	0.001	0.003	**0.0%**	0.0000	0.0002
Hexanes +	92.12	0.2421	0.223	1.097	**1.1%**	0.0154	0.0675
C8 Heavies	96.09	0.0290	0.028	0.137	**0.137%**	0.0019	0.0084
		8.30	20.324	100.000	100%		
		100.0000	**VOC 22.843**		22.8%		

Notes:
Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

EPN: WHHTR1

Name/Type	Well Head Heater
Heater Rating (MMBtu/hr)	0.05
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	Emission Factor (lb/MMCF)	Reference	lb/hr	tpy
VOC	5.5	AP-42	0.0002	0.0010
NOx	100	AP-42	0.0041	0.0178
CO	84	AP-42	0.0034	0.0150
PM_{10}	7.6	AP-42	0.0003	0.0014
$PM_{2.5}$	5.7	AP-42	0.0002	0.0010
SO_2	0.6	AP-42	0.0000	0.0001
HCHO	0.0075	AP-42	0.000000	0.000001
Benzene	0.0021	AP-42	0.000000	0.000000
Toluene	0.0034	AP-42	0.000000	0.000001

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN:	LNHTR1

Name/Type	Line Heater
Heater Rating (MMBtu/hr)	0.5
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	Emission Factor (lb/MMCF)	Reference	lb/hr	tpy
VOC	5.5	AP-42	0.0022	0.0098
NOx	100	AP-42	0.0407	0.1780
CO	84	AP-42	0.0341	0.1496
PM_{10}	7.6	AP-42	0.0031	0.0135
$PM_{2.5}$	5.7	AP-42	0.0023	0.0101
SO_2	0.6	AP-42	0.0002	0.0011
HCHO	0.0075	AP-42	0.000003	0.000013
Benzene	0.0021	AP-42	0.000001	0.000004
Toluene	0.0034	AP-42	0.000001	0.000006

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN: HTRTR1

Name/Type	Heater Treater
Heater Rating (MMBtu/hr)	1
Operating Hours	8760
Fuel Heat Value (Btu/SCF)	1230

Pollutant	**Emission Factor (lb/MMCF)**	**Reference**	**lb/hr**	**tpy**
VOC	5.5	AP-42	0.0045	0.0196
NOx	100	AP-42	0.0813	0.3561
CO	84	AP-42	0.0683	0.2991
PM_{10}	7.6	AP-42	0.0062	0.0271
$PM_{2.5}$	5.7	AP-42	0.0046	0.0203
SO_2	0.6	AP-42	0.0005	0.0021
HCHO	0.0075	AP-42	0.000006	0.000027
Benzene	0.0021	AP-42	0.000002	0.000007
Toluene	0.0034	AP-42	0.000003	0.000012

Calculation Notes:
Natural Gas Combustion Factor Data based on AP-42, Table 1.4-1 - 1.4.3.

EPN: ENG1
Caterpillar G398 TA HCR (Type Engine)
Engine SN:
Man. Date:
Manufacturer's Rated Horsepower 610 hp
Fuel Input 0.007804 MMBtu/hp-hr
Operating Schedule: 8760 hours annually

Pollutant	Reference	Control Efficiency	FACTORS			EMISSIONS	
				lean	rich		
			grams/bhp-hr	lb/MMBtu	lb/MMBtu	lbs/hr	TPY
NOx	Manuf. Engine Data	-----	1.00			1.3436	5.8850
CO	Manuf. Engine Data	-----	2.00			2.6872	11.7700
VOC_{total}	Manuf. Engine Data	-----	0.50			0.6718	2.9425
SO2	AP-42	-----		0.00059	0.00059	0.0028	0.0123
PM10	AP-42	-----		0.00999	0.01941	0.0924	0.4047
PM2.5	AP-42	-----		0.00999	0.01941	0.0924	0.4047
HCHO	AP-42	-----		0.05280	0.02050	0.2514	1.1009
Benzene	AP-42	-----		0.00044	0.00158	0.0075	0.0329
Toluene	AP-42	-----		0.00041	0.00056	0.0027	0.0116
Ethylbenzene	AP-42	-----		0.00004	0.00002	0.0002	0.0008
Xylene	AP-42	-----		0.00018	0.00020	0.0009	0.0041
Acetaldehyde	AP-42	-----		0.00836	0.00279	0.0398	0.1743
Acrolein	AP-42	-----		0.00514	0.00263	0.0245	0.1072
1,1-dichloroethane	AP-42	-----		0.00002	0.00001	0.0001	0.0005
1,2-dichloroethane	AP-42	-----		0.00002	0.00001	0.0001	0.0005
1,1,2-Trichloroethane	AP-42	-----		0.00003	0.00002	0.0002	0.0007
1,1,2,2-Tetrachloroethane	AP-42	-----		0.00004	0.00003	0.0002	0.0008
1,2-dichloropropane	AP-42	-----		0.00003	0.00001	0.0001	0.0006
1,3-butadiene	AP-42	-----		0.00027	0.00066	0.0032	0.0138
1,3-dichloropropene	AP-42	-----		0.00003	0.00001	0.0001	0.0006
2,2,4-Trimethylpentane	AP-42	-----		0.00025		0.0012	0.0052
Benzo(b)fluoranthene	AP-42	-----		0.00000		0.0000	0.0000
Benzo(e)pyrene	AP-42	-----		0.00000		0.0000	0.0000
Biphenyl	AP-42	-----		0.00021		0.0010	0.0044
Carbon Tetrachloride	AP-42	-----		0.00004	0.00002	0.0002	0.0008
Chlorobenzene	AP-42	-----		0.00003	0.00001	0.0001	0.0006
Chloroethane	AP-42	-----		0.00000		0.0000	0.0000
Chloroform	AP-42	-----		0.00003	0.00001	0.0001	0.0006
Chrysene	AP-42	-----		0.00000		0.0000	0.0000
Cyclopentane	AP-42	-----		0.00023		0.0011	0.0047
Ethylene Dibromide	AP-42	-----		0.00004	0.00002	0.0002	0.0009
Methanol	AP-42	-----		0.00250	0.00306	0.0146	0.0638
Methylcyclohexane	AP-42	-----		0.00123		0.0059	0.0256
Methylene Chloride	AP-42	-----		0.00002	0.00004	0.0002	0.0009
n-Hexane	AP-42	-----		0.00111		0.0053	0.0231
n-Nonane	AP-42	-----		0.00011		0.0005	0.0023
n-Octane	AP-42	-----		0.00035		0.0017	0.0073
n-Pentane	AP-42	-----		0.00260		0.0124	0.0542
Naphthalene	AP-42	-----		0.00007	0.00010	0.0005	0.0020
PAH	AP-42	-----		0.00003	0.00014	0.0007	0.0029
Phenol	AP-42	-----		0.00002		0.0001	0.0005
Vinyl Chloride	AP-42	-----		0.00001	0.00001	0.0001	0.0003

Example Calculations:
NOx: ((1.0 grams/bhp-hr)(610 bhp))(1/454) = 1.3436 lbs/hr
NOx: (1.3436 lbs/hr)(8760 hrs/yr)/2000 = 5.8850 TPY

Calculation Notes:
Engine Data based on AP-42 Section 3.2, Manufacturer Engine Data Sheets

EPN: WTRTNK1-4

Water Tank E&P Calculations: ML Investment 1-10,2-10 (Low Pressure Oil)
Operating Schedule: 8760 hours annually

Control Efficiency	0%
Throughput (BWPD)	80
Tank Count	4

Water Tank E&P Calculations					
TANKS		EMISSIONS		EMISSIONS-CONTROLLED	
Size	BWPD	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
400 bbl	20	3.621	15.862	0.0362	0.1586
		Total VOCs		0.1448	0.6345

*Emissions calculated using 1% of emissions represented from condensate

	Reduction %	1%	Total Emissions	
Emissions Speciation	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
Benzene	0.003	0.012	0.0001	0.0005
Toluene	0.003	0.013	0.0001	0.0005
Ethybenzene	0.001	0.003	0.0000	0.0001
Xylenes	0.002	0.010	0.0001	0.0004

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : C:\Documents and Settings\ECS\My Documents\My Notebook\ECS Clients\ECS CLIENT FILES\
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : AP42
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Oil
Entering Air Composition  : No

Filed Name                : ML Investment 1-10, 2-10
Date                      : 2014.06.13

******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure        : 250.00[psig]
Separator Temperature     : 102.00[F]
Ambient Pressure          : 14.70[psia]
Ambient Temperature       : 60.00[F]
C10+ SG                   : 0.7460
C10+ MW                   : 160.99

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component            mol %
   1      H2S                  0.0000
   2      O2                   0.0000
   3      CO2                  0.0000
   4      N2                   0.0000
   5      C1                   4.9554
   6      C2                   1.7233
   7      C3                   3.3193
   8      i-C4                 1.6162
   9      n-C4                 4.0632
   10     i-C5                 2.9444
   11     n-C5                 4.1376
   12     C6                   4.5705
   13     C7                  19.8607
   14     C8                  15.0077
   15     C9                  10.4805
   16     C10+                18.4132
   17     Benzene              0.1247
   18     Toluene              0.4338
   19     E-Benzene            0.2831
   20     Xylenes              1.0386
   21     n-C6                 6.3697
   22     224Trimethylp        0.6584

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 20[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 71.89
Reid Vapor Pressure       : 273.523[psia]
Bulk Temperature          : 102.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                  : 12.00[ft]
Shell Height              : 20.00[ft]
Cone Roof Slope           : 0.06
Average Liquid Height     : 10.00[ft]
Vent Pressure Range       : 0.06[psi]
Solar Absorbance          : 0.68

-- Meteorological Data -------------------------------------------------------------------
```

City	:	Denver, CO
Ambient Pressure	:	14.70[psia]
Ambient Temperature	:	60.00[F]
Min Ambient Temperature	:	36.20[F]
Max Ambient Temperature	:	64.30[F]
Total Solar Insolation	:	1568.00[Btu/ft^2*day]

Calculation Results

-- Emission Summary --

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
Total HAPs	0.760	0.174
Total HC	25.432	5.806
VOCs, C2+	19.022	4.343
VOCs, C3+	15.862	3.621

Uncontrolled Recovery Info.

Vapor	1.6200	[MSCFD]
HC Vapor	1.6200	[MSCFD]
GOR	81.00	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.000	0.000
4	N2	0.000	0.000
5	C1	6.409	1.463
6	C2	3.160	0.721
7	C3	5.233	1.195
8	i-C4	1.798	0.411
9	n-C4	3.392	0.774
10	i-C5	1.298	0.296
11	n-C5	1.367	0.312
12	C6	0.617	0.141
13	C7	1.027	0.234
14	C8	0.278	0.063
15	C9	0.074	0.017
16	C10+	0.021	0.005
17	Benzene	0.012	0.003
18	Toluene	0.013	0.003
19	E-Benzene	0.003	0.001
20	Xylenes	0.010	0.002
21	n-C6	0.688	0.157
22	224Trimethylp	0.032	0.007
	Total	25.432	5.806

-- Stream Data --

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	4.9554	0.3322	0.0000	53.8958	0.0001	51.2626
6	C2	30.07	1.7233	0.5469	0.0000	14.1768	0.0000	13.4842
7	C3	44.10	3.3193	2.2146	0.8513	15.0133	19.4086	15.2280
8	i-C4	58.12	1.6162	1.4297	1.0604	3.5901	11.3572	3.9696
9	n-C4	58.12	4.0632	3.8252	3.1613	6.5826	25.1054	7.4876
10	i-C5	72.15	2.9444	3.0419	2.9465	1.9119	10.0279	2.3085
11	n-C5	72.15	4.1376	4.3419	4.3145	1.9743	11.3092	2.4304
12	C6	86.16	4.5705	4.9334	5.1624	0.7287	5.1006	0.9423
13	C7	100.20	19.8607	21.6426	23.0911	0.9976	8.3801	1.3583

14	C8	114.23	15.0077	16.4043	17.6302	0.2232	2.2323	0.3213
15	C9	128.28	10.4805	11.4657	12.3525	0.0506	0.5941	0.0771
16	C10+	160.99	18.4132	20.1517	21.7379	0.0095	0.1492	0.0163
17	Benzene	78.11	0.1247	0.1351	0.1425	0.0145	0.1060	0.0190
18	Toluene	92.13	0.4338	0.4735	0.5072	0.0133	0.1182	0.0184
19	E-Benzene	106.17	0.2831	0.3096	0.3332	0.0027	0.0280	0.0039
20	Xylenes	106.17	1.0386	1.1359	1.2228	0.0085	0.0908	0.0125
21	n-C6	86.18	6.3697	6.8977	7.2615	0.7804	5.7715	1.0243
22	224Trimethylp	114.24	0.6584	0.7181	0.7680	0.0260	0.2208	0.0356
	MW		101.63	108.31	110.89	30.89	66.55	32.63
	Stream Mole Ratio		1.0000	0.9137	0.9093	0.0863	0.0044	0.0907
	Heating Value	[BTU/SCF]				1805.20	3695.96	1897.58
	Gas Gravity	[Gas/Air]				1.07	2.30	1.13
	Bubble Pt. @ 100F	[psia]	166.49	22.28	6.54			
	RVP @ 100F	[psia]	283.14	81.19	41.31			
	Spec. Gravity @ 100F		0.661	0.670	0.672			

EPN: OILTNK1-10

Oil Tank E&P Calculations: ML Investment 1-10,2-10(Low Pressure Oil)	
Operating Schedule: 8760 hours annually	
Control Efficiency	95%
Throughput (BOPD)	500
Tank Count	10

Oil Tank E&P Calculations					
TANKS		EMISSIONS		EMISSIONS-CONTROLLED	
Size	BOPD	lb/hr ER	Annual (TPY)	lb/hr ER	Annual (TPY)
400 bbl	50	8.765	38.392	0.4383	1.9196
		Total VOCs for all Oil Tanks		4.3825	19.1960

			EMISSIONS-CONTROLLED	
Emissions Speciation	**lbs/hr**	**Tons/yr**	lb/hr ER	Annual (TPY)
Benzene	0.006	0.026	0.0030	0.0130
Toluene	0.007	0.029	0.0035	0.0145
Ethybenzene	0.002	0.007	0.0010	0.0035
Xylenes	0.005	0.023	0.0025	0.0115

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File               : C:\Documents and Settings\ECS\My Documents\My Notebook\ECS Clients\ECS CLIENT FILES\
Flowsheet Selection        : Oil Tank with Separator
Calculation Method         : AP42
Control Efficiency         : 100.0%
Known Separator Stream     : Low Pressure Oil
Entering Air Composition   : No

Filed Name                 : ML Investment 1-10, 2-10
Date                       : 2014.07.07


******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure         : 250.00[psig]
Separator Temperature      : 102.00[F]
Ambient Pressure           : 14.70[psia]
Ambient Temperature        : 60.00[F]
C10+ SG                    : 0.7460
C10+ MW                    : 160.99

-- Low Pressure Oil -----------------------------------------------------------------------
   No.    Component             mol %
   1      H2S                    0.0000
   2      O2                     0.0000
   3      CO2                    0.0000
   4      N2                     0.0000
   5      C1                     4.9554
   6      C2                     1.7233
   7      C3                     3.3193
   8      i-C4                   1.6162
   9      n-C4                   4.0632
   10     i-C5                   2.9444
   11     n-C5                   4.1376
   12     C6                     4.5705
   13     C7                    19.8607
   14     C8                    15.0077
   15     C9                    10.4805
   16     C10+                  18.4132
   17     Benzene                0.1247
   18     Toluene                0.4338
   19     E-Benzene              0.2831
   20     Xylenes                1.0386
   21     n-C6                   6.3697
   22     224Trimethylp          0.6584

-- Sales Oil ------------------------------------------------------------------------------
Production Rate            : 50[bbl/day]
Days of Annual Operation   : 365 [days/year]
API Gravity                : 71.89
Reid Vapor Pressure        : 273.523[psia]
Bulk Temperature           : 102.00[F]

-- Tank and Shell Data --------------------------------------------------------------------
Diameter                   : 12.00[ft]
Shell Height               : 20.00[ft]
Cone Roof Slope            : 0.06
Average Liquid Height      : 10.00[ft]
Vent Pressure Range        : 0.06[psi]
Solar Absorbance           : 0.68

-- Meteorological Data --------------------------------------------------------------------
```

City : Denver, CO
Ambient Pressure : 14.70[psia]
Ambient Temperature : 60.00[F]
Min Ambient Temperature : 36.20[F]
Max Ambient Temperature : 64.30[F]
Total Solar Insolation : 1568.00[Btu/ft^2*day]

****
* Calculation Results *
****

-- Emission Summary --

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
Total HAPs	1.720	0.393
Total HC	62.622	14.297
VOCs, C2+	46.465	10.608
VOCs, C3+	38.392	8.765

Uncontrolled Recovery Info.

Vapor	4.0500	[MSCFD]
HC Vapor	4.0500	[MSCFD]
GOR	81.00	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.000	0.000
4	N2	0.000	0.000
5	C1	16.157	3.689
6	C2	8.073	1.843
7	C3	13.373	3.053
8	i-C4	4.395	1.003
9	n-C4	8.174	1.866
10	i-C5	3.039	0.694
11	n-C5	3.174	0.725
12	C6	1.405	0.321
13	C7	2.299	0.525
14	C8	0.612	0.140
15	C9	0.160	0.037
16	C10+	0.043	0.010
17	Benzene	0.026	0.006
18	Toluene	0.029	0.007
19	E-Benzene	0.007	0.002
20	Xylenes	0.023	0.005
21	n-C6	1.559	0.356
22	224Trimethylp	0.071	0.016
	Total	62.619	14.297

-- Stream Data ---

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	4.9554	0.3322	0.0000	53.8958	0.0001	51.6882
6	C2	30.07	1.7233	0.5469	0.0911	14.1768	4.4925	13.7802
7	C3	44.10	3.3193	2.2146	1.4809	15.0133	28.4792	15.5648
8	i-C4	58.12	1.6162	1.4297	1.2368	3.5901	10.6953	3.8811
9	n-C4	58.12	4.0632	3.8252	3.4801	6.5826	22.0997	7.2182
10	i-C5	72.15	2.9444	3.0419	2.9900	1.9119	8.0158	2.1620
11	n-C5	72.15	4.1376	4.3419	4.3227	1.9743	8.9033	2.2581
12	C6	86.16	4.5705	4.9334	5.0415	0.7287	3.9011	0.8586
13	C7	100.20	19.8607	21.6426	22.3367	0.9976	6.3417	1.2165

14	C8	114.23	15.0077	16.4043	16.9936	0.2232	1.6838	0.2830
15	C9	128.28	10.4805	11.4657	11.8924	0.0506	0.4479	0.0668
16	C10+	160.99	18.4132	20.1517	20.9151	0.0095	0.1135	0.0138
17	Benzene	78.11	0.1247	0.1351	0.1386	0.0145	0.0808	0.0172
18	Toluene	92.13	0.4338	0.4735	0.4897	0.0133	0.0893	0.0164
19	E-Benzene	106.17	0.2831	0.3096	0.3209	0.0027	0.0211	0.0034
20	Xylenes	106.17	1.0386	1.1359	1.1777	0.0085	0.0685	0.0109
21	n-C6	86.18	6.3697	6.8977	7.0705	0.7804	4.3993	0.9287
22	224Trimethylp	114.24	0.6584	0.7181	0.7420	0.0260	0.1669	0.0318
	MW		101.63	108.31	109.87	30.89	61.43	32.14
	Stream Mole Ratio		1.0000	0.9137	0.9100	0.0863	0.0037	0.0900
	Heating Value	[BTU/SCF]				1805.20	3427.55	1871.66
	Gas Gravity	[Gas/Air]				1.07	2.12	1.11
	Bubble Pt. @ 100F	[psia]	166.49	22.28	8.55			
	RVP @ 100F	[psia]	283.14	81.19	51.38			
	Spec. Gravity @ 100F		0.661	0.670	0.671			

EPN: LOAD1

Tank Truck Loading Emissions

Daily Loading	500	bbl/day
Annual Loadout Amount:	7665	Mgal/yr
Maximum Gallons per Hour:	5000	gal/hr
Control Efficiency	98%	

Saturation Factor (Submerged Dedicated):	0.6	
* True Vapor Pressure of Liquid Loaded:	9.00	psia
* Molecular Weight of Vapors:	50	
Temperature '(R) @ 80F:	540	

Pollutant	Emission Factor (lb/1000gal)*	Reference	Control Efficiency	EMISSIONS Annual (TPY)
VOC_{total}	6.23	AP-42	-----	0.4775

Example Calculations:

VOC: (12.46*[(S*P*M)/T,540])*(Mgal/yr)/2000 = VOC TPY

Saturation Factor (Submerged Dedicated):	0.6	
* True Vapor Pressure of Liquid Loaded:	9.00	psia
* Molecular Weight of Vapors:	50	
Temperature '(R) @ 100F:	560	

Pollutant	Emission Factor (lb/1000gal)*	Reference	Control Efficiency	Short Term Emissions lb/hr
VOC_{total}	6.01	AP-42	-----	0.6008

Example Calculations:

VOC: (12.46*[(S*P*M)/T,540])*(Mgal/yr) = VOC lb/hr

* Emisssions were calculated using AP-42, Table 5.2.5
* Input data from Fesco Analysis 7-2-09
* Vapor Pressure - AP42 - Table 7.1-2

Speciation Table

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	52.8958	8.486	27.580	27.6%	VOC Speciation	
Nitrogen	28.013	0.0000	0.000	0.000	0.0%		
Carbon Dioxide	44.01	0.0000	0.000	0.000	0.0%		
Ethane	30.07	14.1768	4.263	13.855	13.9%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	15.0133	6.620	21.516	21.5%	0.1293	0.1027
Iso-butane	58.124	3.5901	2.087	6.782	6.8%	0.0407	0.0324
N-Butane	58.124	6.5826	3.826	12.435	12.4%	0.0747	0.0594
Iso-Pentane	72.151	1.9119	1.379	4.483	4.5%	0.0269	0.0214
N-Pentane	72.151	1.9743	1.424	4.630	4.6%	0.0278	0.0221
N-Hexane	86.07	0.7287	0.627	2.038	2.0%	0.0122	0.0097
Cyclohexane	84.16	0.0000	0.000	0.000	0.0%	0.0000	0.0000
Heptanes	100.21	0.9976	1.000	3.249	3.2%	0.0195	0.0155
Methylcyclohexane	96.17	0.0000	0.000	0.000	0.0%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0260	0.030	0.097	0.1%	0.0006	0.0005
Benzene	78.11	0.0145	0.011	0.037	0.0%	0.0002	0.0002
Toluene	92.14	0.0133	0.012	0.040	0.0%	0.0002	0.0002
Ethylbenzene	106.17	0.0027	0.003	0.009	0.0%	0.0001	0.0000
Xylenes	106.16	0.0085	0.009	0.029	0.0%	0.0002	0.0001
Hexanes +	92.12	0.7804	0.719	2.336	2.3%	0.0140	0.0112
C8 Heavies	96.09	0.2833	0.272	0.885	0.9%	0.0053	0.0042
		31.93	30.769	100.000	100%		
		98.9998	VOC 58.566				

Notes:

Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Facility Flare Calculations

EPN: FLR1

Pilot Combustion Emissions						
				FACTORS	EMISSIONS	
		Pollutant	Reference	lb/MMBtu	lbs/hr	TPY
Hours of Operation	8,760	NOx	AP-42	0.068	0.0052	0.0229
Hours per Day	24	CO	AP-42	0.310	0.0238	0.1044
Throughput (SCFD)	1,500	THC	AP-42	0.140	0.0108	0.0471
Hourly Flowrate (SCFH)	63	VOC	THC %		0.0025	0.0108
Lower heating value (BTU/SCF)	1,230	SO2	AP-42	0.001	0.0001	0.0003
Combustion Rate	0.08	PM10 / soot	AP-42	0.001	0.0001	0.0003
		PM2.5 / soot	AP-42	0.001	0.0001	0.0003

Calculation Notes: *VOCs taken from gas analysis listed below*

Emission Factors are from AP-42 - 13.5

Waste Gas (Tank Vapors) Combustion Emissions						
				FACTORS	EMISSIONS	
		Pollutant	Reference	lb/MMBtu	lbs/hr	TPY
Hours of Operation	8,760	NOx	AP-42	0.068	0.3485	1.5264
Hours per Day	24	CO	AP-42	0.310	1.5888	6.9587
Throughput (SCFD)	100,000	THC	AP-42	0.140	0.7175	3.1427
Hourly Flowrate (SCFH)	4,167	VOC	THC %		0.4202	1.8405
Lower heating value (BTU/SCF)	1,230	SO2	AP-42	0.001	0.0051	0.0224
Combustion Rate	5.13	PM10 / soot	AP-42	0.001	0.0051	0.0224
		PM2.5 / soot	AP-42	0.001	0.0051	0.0224

Calculation Notes: *VOCs taken from gas analysis listed below*

Emission Factors are from AP-42 - 13.5

Field Gas or Pilot Gas

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	84.8561	13.613	66.981	67.0%	VOC Speciation	
Nitrogen	28.013	0.4883	0.137	0.673	0.7%		
Carbon Dioxide	44.01	0.1433	0.063	0.310	0.3%		
Ethane	30.07	6.2131	1.868	9.192	9.2%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	4.0209	1.773	8.724	8.7%	0.0002	0.0009
Iso-butane	58.124	0.9324	0.542	2.666	2.7%	0.0001	0.0003
N-Butane	58.124	1.5751	0.916	4.505	4.5%	0.0001	0.0005
Iso-Pentane	72.151	0.5374	0.388	1.908	1.9%	0.0000	0.0002
N-Pentane	72.151	0.5433	0.392	1.929	1.9%	0.0000	0.0002
N-Hexane	86.07	0.2249	0.194	0.952	1.0%	0.0000	0.0001
Cyclohexane	84.16	0.0342	0.029	0.142	0.1%	0.0000	0.0000
Heptanes	100.21	0.1201	0.120	0.592	0.6%	0.0000	0.0001
Methylcyclohexane	96.17	0.0266	0.026	0.126	0.1%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0068	0.008	0.038	0.0%	0.0000	0.0000
Benzene	78.11	0.0035	0.003	0.013	0.0%	0.0000	0.0000
Toluene	92.14	0.0021	0.002	0.010	0.0%	0.0000	0.0000
Ethylbenzene	106.17	0.0003	0.000	0.002	0.0%	0.0000	0.0000
Xylenes	106.16	0.0005	0.001	0.003	0.0%	0.0000	0.0000
Hexanes +	92.12	0.2421	0.223	1.097	1.1%	0.0000	0.0001
C8 Heavies	96.09	0.0290	0.028	0.137	0.1%	0.0000	0.0000
		8.30	20.324	100.000	100%		
		100.0000	**VOC 22.8**				

Notes:
Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Waste Gas

Component	Mole Wt	Mole%	lb/mol Mix	Wt%	Percentage	EMISSIONS lbs/hr	EMISSIONS TPY
Methane	16.043	52.8958	8.486	27.580	27.6%	VOC Speciation	
Nitrogen	28.013	0.0000	0.000	0.000	0.0%		
Carbon Dioxide	44.01	0.0000	0.000	0.000	0.0%		
Ethane	30.07	14.1768	4.263	13.855	13.9%		
Hydrogen Sulfide	34.08	0.0000	0.000	0.000	0.0%		
Propane	44.097	15.0133	6.620	21.516	21.5%	0.0904	0.3960
Iso-butane	58.124	3.5901	2.087	6.782	6.8%	0.0285	0.1248
N-Butane	58.124	6.5826	3.826	12.435	12.4%	0.0523	0.2289
Iso-Pentane	72.151	1.9119	1.379	4.483	4.5%	0.0188	0.0825
N-Pentane	72.151	1.9743	1.424	4.630	4.6%	0.0195	0.0852
N-Hexane	86.07	0.7287	0.627	2.038	2.0%	0.0086	0.0375
Cyclohexane	84.16	0.0000	0.000	0.000	0.0%	0.0000	0.0000
Heptanes	100.21	0.9976	1.000	3.249	3.2%	0.0137	0.0598
Methylcyclohexane	96.17	0.0000	0.000	0.000	0.0%	0.0000	0.0000
224-Trimethylpentane	114.22	0.0260	0.030	0.097	0.1%	0.0004	0.0018
Benzene	78.11	0.0145	0.011	0.037	0.0%	0.0002	0.0007
Toluene	92.14	0.0133	0.012	0.040	0.0%	0.0002	0.0007
Ethylbenzene	106.17	0.0027	0.003	0.009	0.0%	0.0000	0.0002
Xylenes	106.16	0.0085	0.009	0.029	0.0%	0.0001	0.0005
Hexanes +	92.12	0.7804	0.719	2.336	2.3%	0.0098	0.0430
C8 Heavies	96.09	0.2833	0.272	0.885	0.9%	0.0037	0.0163
		31.93	30.769	100.000	100%		
		98.9998	**VOC 58.6**				

Notes:
Gas Analysis - Questar Applied Technology, 1/3/2013, ML Investments 1-10

Alta Mesa Services, LP
Well Site Facility - GHG Emission Summary

GHG Pollutant	Compressor Engines	Well Head Heater	Line Heater	Heater Treater	Flare	Emission Totals
	ENG1	WHHTR1	LNHTR1	HTRTR1	FLR1	
	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	Metric Ton CO2e	
CO2	2211.0111	23.2228	232.2276	464.4552	4797.8222	**7728.7389**
CH4	0.8757	0.0092	0.0920	0.1840	1.9003	**3.0612**
N2O	1.2927	0.0136	0.1358	0.2716	2.8052	**4.5189**
Total GHG Metric Ton CO2e						**7736.32**

EPN: ENG1
Compressor Engine

Manufacturer's Rated Horsepower	610	hp
Fuel Input	0.007804	MMBtu/hp-hr
Operating Schedule	8760	hrs/yr

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Reference	Control Efficiency	Emission Factors	Factor Units	Short Term Emissions (kg/hr)	Annual Emissions (kg/yr)	**Metric Ton CO2e**
CO2	EPA GHG Factors	-----	53.02	kg/mmBtu	252.3985	2211011.1	**2211.0**
CH4	EPA GHG Factors	-----	0.001	kg/mmBtu	0.0048	41.70	**0.8757**
N2O	EPA GHG Factors	-----	0.0001	kg/mmBtu	0.0005	4.17	**1.2927**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	WHHTR1

Name/Type	Well Head Heater
Heater Rating (mmBtu/hr)	0.05
Operating Hours	8760
mmBtu/yr	438
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	**Emission Factor**	**Factor Units**	**Reference**	**Annual Emissions (kg/yr)**	**Metric Ton CO2e**
CO2	53.02	kg/mmBtu	EPA GHG Factors	23,222.76	**23.2228**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	0.44	**0.0092**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.04	**0.0136**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	LNHTR1

Name/Type	Line Heater
Heater Rating (mmBtu/hr)	0.5
Operating Hours	8760
mmBtu/yr	4380
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO2e
CO2	53.02	kg/mmBtu	EPA GHG Factors	232,227.60	**232.2276**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	4.38	**0.0920**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.44	**0.1358**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	HTRTR1

Name/Type	Heater Treater
Heater Rating (mmBtu/hr)	1
Operating Hours	8760
mmBtu/yr	8760
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH4	21
N2O	310

Pollutant	Emission Factor	Factor Units	Reference	Annual Emissions (kg/yr)	Metric Ton CO2e
CO2	53.02	kg/mmBtu	EPA GHG Factors	464,455.20	**464.4552**
CH4	0.001	Kg/mmBtu	EPA GHG Factors	8.76	**0.1840**
N2O	0.0001	Kg/mmBtu	EPA GHG Factors	0.88	**0.2716**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

EPN:	FLR1

Name/Type	Flare
Heater Rating (mmBtu/hr)	10.33
Operating Hours	8760
mmBtu/yr	90490.8
Fuel Heat Value (Btu/SCF)	1230

Global Warming Potentials	
CH_4	21
N_2O	310

Pollutant	**Emission Factor**	**Factor Units**	**Reference**	**Annual Emissions (kg/yr)**	**Metric Ton CO2e**
CO_2	53.02	kg/mmBtu	EPA GHG Factors	4,797,822.22	**4797.8222**
CH_4	0.001	Kg/mmBtu	EPA GHG Factors	90.49	**1.9003**
N_2O	0.0001	Kg/mmBtu	EPA GHG Factors	9.05	**2.8052**

Calculation Notes:
Factor Data based on EPA's GHG Published Emission Factors(11/7/2011)

M E M O R A N D U M

DATE: June 3, 2016

TO: Kelli Wetzel, Permit Writer, Air Program

FROM: Kevin Schilling, Stationary Source Modeling Coordinator, Air Program

PROJECT: P-2015.0053 PROJ 61600, PTC for Alta Mesa Services, DJS 1-15 Well Site Facility in Payette County, ID

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Alta Mesa	Alta Mesa Services, LP
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality modeling system
CO	Carbon Monoxide
DEM	Digital Elevation Map
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
GEP	Good Engineering Practice
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
m	Meters
m/sec	Meters per second
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NWS	National Weather Service
O_3	Ozone
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	parts per billion
PRIME	Plume Rive Model Enhancement
PTC	Permit to Construct
PTE	Potential to Emit
SIL	Significant Impact Level
SO_2	Sulfur Dioxide

TAP	Toxic Air Pollutant
TCEQ	Texas Commission on Environmental Quality
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
W&A	Wolcott & Associates ECS, LLC
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

Alta Mesa Services, LP (Alta Mesa) submitted a Permit to Construct (PTC) application for a proposed oil and gas production well site facility, DJS 1-15, located 6.7 miles east of the Idaho/Oregon boundary at Ontario, Oregon, and about 4.5 miles north, northeast of New Plymouth, Idaho. The original PTC application was received on September 30, 2015. DEQ determined the application was incomplete on October 28, 2015. After additional data/analyses were received, the application was again determined incomplete on November 28, 2015, and again on December 30, 2015. On February 16, 2016, revised air impact analyses were received by DEQ and the application was determined complete on April 13, 2016.

This memorandum provides a summary of the ambient air impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification and sensitivity analyses, additional clarifications, and conclusions.

Project-specific air quality analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

Wolcott & Associates ECS, LLC (W&A), on behalf of Alta Mesa, prepared the PTC application and performed the ambient air impact analyses for this project to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Toxic Air Pollutants (TAPs). The DEQ review of submitted data and analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with operation of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emissions estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emissions calculation methods were not evaluated in this modeling review memorandum.

The submitted information and analyses, in combination with DEQ's verification analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that TAP emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Idaho Air Rules require air impact analyses be conducted according to methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses, in combination with DEQ's analyses, demonstrated to the satisfaction of the Department that operation of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit provisions/restrictions to assure the requirements of Appendix W are met with regard to emissions representing design capacity or permit allowable rates.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
General Emissions Rates. Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, must represent maximum potential emissions as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses.
Below Regulatory Concern for Criteria Pollutant Emissions. Maximum non-fugitive annual emissions of PM_{10}[a], $PM_{2.5}$[b], carbon monoxide (CO), sulfur dioxide (SO_2), and lead (Pb) are below levels identified as below regulatory concern (BRC) as per Idaho Air Rules Section 221, and the project would be exempt from permitting if it were not for uncontrolled emissions of some criteria pollutants exceeding BRC threshold levels.	Idaho Air Rules Section 203.02, requiring air impact analyses demonstrating compliance with NAAQS, is not applicable to pollutants having a project-emissions increase that is less than BRC levels, provided the project would have qualified for a BRC permitting exemption except for the emissions levels of another criteria pollutant exceeding the ton/year BRC threshold.
Stack Parameter Variability. Provided the equipment installed and operated at the DJS 1-15 site is representative of what was described in the application, moderate variability in operational parameters, other than a decrease in stack heights or the addition of structures not accounted for in the submitted analyses, will not change the conclusion of the NAAQS compliance demonstration. Such parameters include operational load levels of the engine, heaters, and flare, stack diameters, and stack exhaust temperatures.	DEQ performed a sensitivity analysis using values for emissions release parameters that were more conservative than those used in the submitted analyses. Results of sensitivity analyses still easily demonstrated compliance with NAAQS.

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

The DJS 1-15 facility will be an oil and gas gathering and processing facility. The PTC will address all air pollutant emitting activities at the site.

2.2 Proposed Location and Area Classification

The proposed facility will be located about 6.7 miles east of the Idaho/Oregon boundary at Ontario, Oregon, and about 4.5 miles north, northeast of New Plymouth, Idaho. It is located in Payette County, Idaho. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS**. The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.** Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

> ***02. Estimates of Ambient Concentrations**. All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from facility-wide potential/allowable emissions, and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	**Averaging Period**	**Significant Impact Levels[a] ($\mu g/m^3$)[b]**	**Regulatory Limit[c] ($\mu g/m^3$)**	**Modeled Design Value Used[d]**
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6^{th} highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8^{th} highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2^{nd} highest[n]
	8-hour	500	10,000[m]	Maximum 2^{nd} highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4^{th} highest[q]
	3-hour	25	1,300[m]	Maximum 2^{nd} highest[n]
	24-hour	5	365[m]	Maximum 2^{nd} highest[n]
	Annual	1.0	80[r]	Maximum 1^{st} highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8^{th} highest[t]
	Annual	1.0	100[r]	Maximum 1^{st} highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1^{st} highest[n]
	Quarterly	NA	1.5[r]	Maximum 1^{st} highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1^{st} highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98^{th} percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8^{th} highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1^{st} highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99^{th} percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4^{th} highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1^{st} highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98^{th} percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8^{th} highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4^{th} highest daily maximum 8-hour concentration averaged over three years. The O_3 standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. As an example, consider a hypothetical case where the SIL analysis indicates the project (new source or modification) has impacts exceeding the SIL and the cumulative impact analysis indicates a violation of the NAAQS. If project-specific impacts are below the SIL at the specific receptors showing the violations during the time periods when modeled violations occurred, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emissions increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis resulted in modeled NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the Alta Mesa DJS 1-15 facility were provided by W&A for various applicable averaging periods.

Review and approval of estimated emissions is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emissions estimates is not addressed in this modeling memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emissions inventory. All modeled criteria air pollutant and TAP emissions rates must be equal to or greater than the facility's potential emissions calculated in the PTC emissions inventory or proposed permit allowable emissions rates.

3.1.1 Modeling Applicability and Modeled Criteria Pollutant Emissions Rates

Facility-wide potential to emit (PTE) values for all criteria pollutants would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of volatile organic compounds (VOCs) exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

The DEQ permit writer should assure that the final emissions inventory indicates that facility-wide controlled PTE emissions of PM_{10}, $PM_{2.5}$, SO_2, and Pb are below BRC levels, as listed in Table 3. Table 3 also indicates that air impact analyses for CO and NO_2 are required for permit issuance.

An air impact analysis must be performed for pollutant increases that would not qualify for the BRC exemption from the requirement to perform an air impact analysis. Facility-wide emissions of CO and NOx from operation of the DJS 1-15 facility do not qualify for the BRC exclusion because allowable emissions will exceed BRC threshold levels.

Table 3. CRITERIA POLLUTANT NAAQS COMPLIANCE DEMONSTRATION APPLICABILITY			
Criteria Pollutant	**BRC Level (ton/year)**	**Applicable Facility Wide PTE Emissions (ton/year)**	**Air Impact Analyses Required?**
PM_{10}[a]	1.5	0.47	No
$PM_{2.5}$[b]	1.0	0.46	No
Carbon Monoxide (CO)	10.0	19.3	Yes
Sulfur Dioxide (SO_2)	4.0	0.04	No
Nitrogen Oxides (NOx)	4.0	8.0	Yes
Lead (Pb)	0.06	NA[c]	No

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Not calculated. Assumed to be below BRC levels based on the emissions source types.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling thresholds, below which a site-specific modeling analysis is not required. DEQ generic modeling analyses that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If project-specific total emissions rates of a pollutant are below Level I Modeling Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Thresholds are conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emissions sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

DEQ determined that Level II Modeling Thresholds are not appropriate for the proposed project. Level II thresholds were based on modeling of a hypothetical source with less conservative parameters than was used in modeling to support Level I thresholds. Table 4 compares dispersion-affecting parameters associated with the proposed project to those used in modeling analyses establishing the Level II thresholds. DEQ determined Level II Modeling Applicability Thresholds were not appropriate for the site on the basis of the short stack heights of the sources and the very short distance from sources to ambient air. Table 5 provides a summary of the site-specific modeling applicability analysis.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Table 4. COMPARISON OF DISPERSION PARAMETERS BETWEEN LEVEL II THRESHOLD MODELING AND THE PROPOSED PROJECT		
Parameter	**Analyses for Level II Modeling**	**Proposed Project**
Stack Height (meters)	15	<6.1 for all sources
Stack Temperature at Exit (^{o}F)	260	1,162 for engine 1,832 for flare
Stack Gas Velocity at Exit (meters/second)	20	53.4 for engine 20 for flare
Total Flow Volume (acfm)	33,288	3,673 for engine 15,165 for flare
Distance to Ambient Air (meters)	100	4.5 for engine 14 for flare
Presence of Buildings	10m X 10m X 5m high building	small engine building and storage silos
Potential for Exposure to Sensitive Receptors	Moderate	Low

Table 5. SITE-SPECIFIC MODELING APPLICABILITY ANALYSIS RESULTS					
Pollutant	**Averaging Period**	**Emissions**	**Level I Modeling Thresholds**	**Level II Modeling Thresholds[a]**	**Modeling Required**
NOx	1-hour	1.82 lb/hr	0.20	2.4	Yes
	Annual	7.99 ton/yr	1.2	14	Yes
CO	1-hour, 8-hour	4.4 lb/hr	15	175	No
Pb	monthly	<14 lb/month	14		No

a. Level II Modeling Thresholds were not approved by DEQ for this project.

Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis because allowable emissions estimates of VOCs and NOx are below the 100 tons/year threshold.

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NOx, SO_2, and/or VOCs was assumed by DEQ to be negligible on the basis of the magnitude of emissions and the short distance from emissions sources to locations where maximum PM_{10} and $PM_{2.5}$ impacts are anticipated.

Emissions Rates Used in Impact Analyses

Table 6 lists the emissions rates used for specified averaging periods in the air impact modeling analyses. These rates must be representative of PTE as indicated by design capacity or as limited by an enforceable permit provision.

Table 6. EMISSIONS RATES USED IN IMPACT MODELING ANALYSES

Source Modeled Identification Code	Description	UTM[a] Coordinates (meters)		Emissions (pounds/hour)	
		Easting	Northing	1-Hour NO_2	Annual NO_2
ENG1	Caterpillar G398TA Engine	515936	4875757	1.344	1.344
FLR1	Plant Flare	515971	4875754	0.3537	0.3537
WHHTR1	Well Head Heater	515924	4875782	0.0041	0.0041
LNHTR1	Line Heater	515925	4875778	0.0407	0.0407
HTRTR1	Heater Treater	515930	4875769	0.0813	0.0813

a. Universal Transverse Mercator

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 210 are only applicable to new or modified sources constructed after July 1, 1995. TAP compliance for the DJS 1-15 facility was demonstrated on a facility-wide basis.

Many of the TAP emissions sources at the Alta Mesa DJS 1-15 facility are regulated under 40 CFR 60, 61, or 63. These sources are exempt from TAP rules as per Idaho Air Rules Section 210 and were excluded from the TAP modeling applicability calculation.

After excluding emissions from sources exempt from the TAPs rules, no project-wide emissions of any TAP exceeded the applicable emissions screening levels (ELs) of Idaho Air Rules Section 585 or Section 586. Consequently, air impact modeling analyses were not required to demonstrate that impacts of TAP emissions are below the applicable ambient increment standards expressed in Idaho Air Rules Section 585 and 586.

3.1.3 Emissions Release Parameters

Table 7 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for emissions sources modeled in the air impact analyses.

W&A provided detail documentation and justification of emissions release parameters within the *Air Impact Modeling Analyses Report* (Section 4.3), submitted as part of the application on February 16, 2016. Parameters represent best or conservative design information at the time of permit application submittal. DEQ performed sensitivity analyses to evaluate whether NAAQS compliance is still assured if release parameters change somewhat with final design. If release parameters change substantially with final design such that parameters no longer are a conservative representation of the emissions sources, then these air impact analyses may effectively be invalidated and will not satisfy the requirements of Idaho Air Rules Section 203.02 and 203.03. Substantial changes from what was submitted in the application would include: 1) a decrease in stack height by more than about 10 percent; 2) a decrease in stack gas flow temperature by more than about 20 percent; 3) a change in source location by more than 10 meters, especially if closer to an ambient air boundary or closer to the design value receptor location; 4) construction of buildings in the vicinity of emissions sources that could cause plume downwash.

Table 7. POINT SOURCE STACK PARAMETERS USED INIMPACT MODELING ANALYSES

Release Point	Description	UTM[a] Coordinates		Stack Height (m)	Stack Gas Flow Temp. (K)[c]	Stack Flow Velocity (m/sec)[d]	Stack Dia. (m)
		Easting (m)[b]	Northing (m)				
ENG1	Catepillar G398TA Engine	515936	4875757	6.1	900, 720[e]	53.4, 16.6[e]	0.203, 0.305[e]
FLR1	Plant Flare	515924	4875782	6.1	1273	20.0	0.675, 0.37[e]
WHHTR1	Well Head Heater	515925	4875778	3.7	422	22.3, 11.7[e]	0.152
LNHTR1	Line Heater	515930	4875769	3.7	422	22.3, 11.7[e]	0.152
HTRTR1	Heater Treater	515971	4875754	3.7	422	22.3, 11.7[e]	0.152

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters/second. All sources release uninterrupted in the vertical direction (not horizontal or rain capped releases).
e. Values used in DEQ verification/sensitivity analyses where such values are different from those used in the analyses submitted with the application.

Engine Release Parameters

DEQ recommended that W&A estimate stack parameters for engines using methods provided in the Washington State Department of Ecology document, *Suitability of Diesel-Powered Emergency Generators for Air Quality General Order of Approval: Evaluation of Control Technology, Ambient Impacts, and Potential Approval Criteria*, published in June 2006. The engine exhaust flow was based on the horsepower (hp) rating of the engine (610 hp) by the following equation from the guidance:

$$\frac{0.284\ m^3/sec}{100\ hp} \times 610\ hp = 1.732\ m^3/sec$$

The guidance recommends using a 44.6 meter/second stack gas exit velocity and then calculating the diameter that would result in a total flow equal to the exhaust flow calculated by the equation above. W&A indicated in Table 4-4 of the submitted modeling report that an exit velocity of 23.7 meters/second was used in the impact analyses, calculated on the basis of a 12-inch stack diameter and maintaining the 1.73 cubic meter/second flow. This is inconsistent with the parameters listed in Table 4-3 of the modeling report and the submitted model input files. The model input files indicate that an exhaust exit velocity of 53.4 meters/second was used with a 0.203-meter stack diameter, still maintaining the 1.73 cubic meter/second flow.

The discrepancy in exhaust flow velocity and stack diameter present in the modeling report could affect the ability to demonstrate NAAQS compliance. Higher exhaust exit velocity results in a higher plume momentum flux, which results in higher plume rise and lower estimated ground-level impacts. However, because of the high temperature of the exhaust, the buoyancy flux may dominate plume rise calculations in the model under most conditions. To address this concern, DEQ performed sensitivity analyses using the larger stack diameter and resulting lower exhaust exit velocity. DEQ sensitivity analyses are discussed in Section 4.1.2 of this memorandum.

W&A estimated exhaust temperatures using a table in the Department of Ecology's guidance that lists exit gas temperatures for various power ratings of engines, interpolating between the value of 897 Kelvin for a 500 hp engine and 1,100 Kelvin for a 6,900 hp engine.

DEQ performed sensitivity analyses using more conservative parameters for the engine exhaust. These adjusted parameters were as follows:

- A flow rate of 70 percent of what was used in the submitted analyses to account for operations at a reduced rate. This results in a 1.21 cubic meters/second flow rate.
- A stack diameter of 0.305 meters, resulting in a corresponding exhaust exit velocity of 16.6 meters/second for a 1.21 cubic meter/second flow.
- An exhaust temperature reduction by 20 percent to 720 Kelvin.

Flare Release Parameters

Modeling impacts from an open flame flare presents challenges because the appropriate method for estimating stack release parameters is not readily evident for point source model inputs of stack diameter, stack gas exist velocity, and stack gas exit temperature. Various methods have been developed to calculate appropriate release parameter values for flares, all primarily involving the heat input of the gas stream flared and the radiative heat loss. W&A used a method specified by the Texas Commission on Environmental Quality (TCEQ). The application provided a copy of the TCEQ guidance for using the method and a description of the technical basis for the approach.

The TCEQ methods for calculating model input parameters for a flare are very similar to those used in the EPA screening model SCREEN3 for flares, as described in the SCREEN3 User's Guide[3]. The method sets the exit gas velocity and temperature constant at 20 meters/second and 1,273 Kelvin, respectively. The stack diameter is then calculated based on the heat released from the combustion of gases in the flare by the following equation:

$$D = [(q_n)(10^{-6})]^{1/2}$$
$$q_n = q[1 - 0.048(MW)^{1/2}]$$

where:

D = effective stack diameter (meters)
q = gross heat released (calories/second)
q_n = net heat released (calories/second)
MW = weighted average molecular weight of gas flared

The gross heat release of 6.23 E5 calories/second was provided by W&A and was based on the molecular composition of the flared gas, expressed as mole/day of specific compounds. The weighted average molecular weight was calculated based on the mole fraction of specific compounds in the flared gas and the molecular weight of those compounds. The net heat released was then calculated at 4.55 E5 calories/second, giving an effective diameter of 0.675 meters.

Provided the composition of the flared gas is accurate or conservative for the source, DEQ asserts that the TCEQ method is appropriate for estimating model input parameters for the flare. To provide additional assurance, DEQ performed sensitivity analyses using the SCREEN3 method. DEQ also adjusted input parameters of the SCREEN3 method to represent a more conservative assessment. These adjustments included the following:

- Not taking credit for additional release height according to a calculation of "length of flame" of the operating flare.
- Calculate the effective diameter (which affects the buoyancy flux of the emitted plume) using a value of half that of q_n.

In the SCREEN3 method, the net heat released is calculated by:

$$q_n = (0.45)q$$

where:
q = gross heat released (calories/second)
q_n = net heat released (calories/second)

The effective diameter is then calculated by $D = 9.88E\text{-}4(q_n)^{0.5}$

Using a gross heat release (q) of 6.23 E5 calories/second results in a net heat release (q_n) of 2.80 E5 calories/second. The effective diameter (D) was then calculated at 0.52 meters. DEQ used an additional measure of conservatism by recalculating the effective diameter (D) by assuming only half the net heat release, equal to 1.4 E5 calories/second, giving a value of D = 0.37 meters.

The SCREEN3 method directs the use of a stack gas release velocity of 20 meters/second and a stack gas temperature of 1,273 Kelvin, identical to that used for the TCEQ method.

The stack height used for a flare release for the SCREEN3 method can be increased from the physical height of the flare to account for the flame length according to the following equation:

$$Ha = Hs + [(4.56E\text{-}3)(q^{0.478})]$$

where:
Ha = effective stack height (meters)
Hs = physical height of flare (meters)
q = gross heat release (calories/second)

DEQ's sensitivity analyses did not account for an increased release height, adding an additional level of conservatism to the results.

Process Heater Release Parameters

Specific process heaters have not yet been selected for the facility. Release parameters were estimated by W&A using a Utah Department of Environmental Quality approach for modeling generic natural gas well sites, as described in the submitted application. A 3.0 million British thermal unit/hour (MMBtu/hr) heater was estimated to produce an exhaust flow of 860 actual cubic feet/minute (acfm) at 600^{o} F, resulting in a 22.2 meter/second exit velocity, given a design specified stack diameter at the exit of 0.5 feet (0.152 meters). As a conservative measure, W&A modeled the sources with an exhaust temperature of 300^{o} F (422 K) rather than 600^{o} F, reducing the effect of plume rise from thermal buoyancy.

DEQ performed a combustion evaluation on the source to verify flow rates. At 100 percent load and combusting with 5.0 percent excess air, a flow of 906 acfm was predicted at a temperature of 300^{o} F. DEQ sensitivity analyses were then performed by conservatively using half the calculated flow to account for operations at less than design capacity. Emissions rates were not correspondingly reduced with the flow associated with reduced load, thereby adding another level of conservatism to the analyses.

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS air impact modeling analysis is needed to demonstrate compliance with applicable NAAQS. DEQ provided W&A with appropriate background concentrations for 1-hour and annual averaged NO_2.

Background concentrations were determined by DEQ using the following web-based design value concentration tool: Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) Lookup 2009-2011 Design Values of Criteria Pollutants (http://lar.wsu.edu/nw-airquest/lookup.html). These design value air pollutant levels are based on regional scale air pollution modeling of Washington, Oregon, and Idaho, with values influenced by monitoring data as a function of distance from the monitor. The background concentration tool estimated the following background values for the Alta Mesa sites in the Payette area: 1-hour NO_2 = 52.6 $\mu g/m^3$; annual NO_2 = 4.7 $\mu g/m^3$. During review of the PTC application, DEQ obtained refined background values for the DJS 1-15 site and they were identical to originally provided values: 1-hour NO_2 = 52.6 $\mu g/m^3$; annual NO_2 = 4.7 $\mu g/m^3$. These refined background values are appropriate for impacts that are within the modeled domain.

3.3 NAAQS Impact Modeling Methodology

This section describes the modeling methods used by the applicant's consultant and DEQ to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Impact Analyses

W&A performed the project-specific air pollutant emissions inventory and air impact analyses that were submitted with the application. Results of the submitted information/analyses, in combination with DEQ's verification and sensitivity analyses, demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 8 provides a brief description of parameters used in the modeling analyses.

Table 8. MODELING PARAMETERS

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Payette, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	Langley Gulch site data, Ontario, OR, surface data, Boise upper air data	December 2008 - November 2009. See Section 3.3.5 of this memorandum for additional details of the meteorological data.
Terrain	Considered	USGS National Elevation Dataset (NED) files to establish elevations of ground level receptors. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1	DEQ: 10-meter spacing along the property boundary out to about 100 meters
	Grid 2	DEQ: 25-meter spacing out to 500 meters.
	Grid 3	DEQ: 100-meter spacing out to 7,000 meters.

3.3.2 Modeling protocol and Methodology

A modeling protocol, describing data and methods proposed for the project, was not initially submitted to DEQ. W&A corresponded with DEQ on modeling methods and data after Alta Mesa received a notice of incomplete application for the DJS 1-15 project. Final project-specific modeling and other required impact analyses were generally conducted using data and methods as discussed with DEQ and as described in the *Idaho Air Quality Modeling Guideline*[2].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 15181 was used by W&A for the modeling analyses to evaluate impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.4 NO_2 Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NOx emissions. The conversion of NO to NO_2 can be conservatively addressed through the use of several methods as outlined in a 2014 EPA NO_2 Modeling Clarification Memorandum[4]. The guidance outlines a three-tiered approach:

- Tier 1 – assume full conversion of NO to NO_2 where total NOx emissions are modeled and modeled impacts are assumed to be 100 percent NO_2.
- Tier 2 – use an ambient ratio to adjust impacts from the Tier 1 analysis.
- Tier 3 – use a detailed screening method to account for $NO/NO_2/O_3$ chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM).

W&A used the Tier 2 Ambient Ratio Method 2 (ARM2) to conservatively account for NO/NO_2 chemistry. A minimum and maximum NO_2/NOx ratio of 0.5 and 0.9 were specified in the model, respectively. The NO_2 Modeling Clarification Memorandum outlines criteria for the acceptability of using ARM2 for a project. DEQ accepted the use of ARM2 for the proposed DJS 1-15 project on the basis of the following:

- A Tier 1 impact assessment of the facility, assuming full conversion of NO to NO_2, resulted in NO_2 modeled impacts below the lower end of the EPA-identified threshold of 150-200 ppb (282-376 $\mu g/m^3$). The lower end of the range is recommended for areas with higher background ozone levels and higher background NO_2 values. The Tier 1 1-hour NO_2 design value for the DJS 1-15 site is 131 $\mu g/m^3$, well below the lower end of the threshold.
- If the Tier I analysis impacts exceed the 282-376 $\mu g/m^3$ threshold, use of the ARM2 method may still be acceptable if the NO_2/NOx in-stack ratio (ISR) of the primary source is at or below 0.2; an ISR above 0.2 may still be acceptable if the minimum ISR of 0.5 is specified as input to the

ARM2 algorithm. Since the facility's design value impact from the Tier 1 analysis is less than the 282-376 $\mu g/m^3$ threshold, assessment of the ISR was not necessary. As a conservative measure, W&A used ARM2 with the minimum ISR of 0.5 rather than 0.2.

- If the Tier I analysis impacts exceed the 282-376 $\mu g/m^3$ threshold, use of the ARM2 method may still be acceptable if the ambient background O_3 levels are not greater than 80 – 90 ppb for more than seven days per year. Since the facility's design value impact from the Tier 1 analysis is less than the 282-376 $\mu g/m^3$ threshold, assessment of the background O_3 was not necessary. However, ARM2 justification for other DEQ air permitting projects assessed background O_3 based on data collected from Middleton, Idaho, between 2002 and 2006. Those data indicated that on average, O_3 exceeds 80 ppb for 2.8 days/year and exceeds 90 ppb for 0.6 days/year.

3.3.5 Meteorological Data

DEQ provided A&W with model-ready meteorological data, using site data from a station at the Langley Gulch Power plant, located along Interstate Highway 84, south of New Plymouth. The Langley Gulch site is about nine miles south of the DJS 1-15 site. Onsite data collected included wind speed, wind direction, delta temperature, and solar radiation. These data were supplemented with National Weather Service (NWS) surface data from the Ontario, Oregon, site KONO, including one minute ASOS data. Upper air data were obtained from the NWS site in Boise, Idaho.

DEQ processed the Langley Gulch meteorological data using AERMET Version 15181, AERMINUTE Version 15271, and AERSURFACE 13016.

DEQ determined that meteorological data from the Langley Gulch site were more representative of conditions at various Alta Mesa sites than data collected at the Boise Airport. Alta Mesa representatives asserted that using a 5-year dataset from Boise would be more defensible and appropriate than using the single year of data from the Langley Gulch site. To address this concern, DEQ performed a sensitivity analysis using surface meteorological data from Boise for the years 2011 through 2015. Results of this analysis are provided in Section 4.1.2 of this memorandum and indicate that use of the Langley Gulch meteorological is conservative, resulting in a higher design value than Boise meteorological data. This is not an indication that Langley Gulch data are more appropriate or more representative of site conditions than Boise Airport data. It simply eliminates the need to evaluate comparative appropriateness and representativeness because NAAQS compliance is demonstrated for both datasets.

3.3.6 Effects of Terrain on Modeled Impacts

Submitted ambient air impact analyses used terrain data extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files in the WGS84 datum (approximately equal to the NAD83 datum).

The terrain preprocessor AERMAP Version 11103 was used by W&A to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

3.3.7 Facility Layout

DEQ verified proper identification of the site location, equipment locations, and the ambient air boundary by comparing a graphical representation of the modeling input file to plot plans submitted in the application. Aerial photographs on Google Earth (available at https://www.google.com/earth) were used to assure that horizontal coordinates were accurate as described in the application. Google Earth could not be used to verify the position of sources and structures because the facility is not yet in existence.

3.3.8 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes were accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of proposed buildings were used as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME) to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information for input to AERMOD. The only structure at the site evaluated for downwash was a 10-foot high structure housing the generator and six 20-foot high storage tanks. The addition of any other structures at the site could cause plume downwash and potentially invalidate the analyses described in this memorandum for NAAQS compliance demonstration purposes.

3.3.9 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." Ambient air was considered areas external to the Alta Mesa DJS-15 facility, and the facility is fenced to preclude public access. DEQ has determined that measures described in the application to preclude public access to areas of the site excluded from ambient air are adequate.

3.3.10 Receptor Network

Table 8 describes the receptor grid used in the submitted analyses. The receptor grid used in the submitted analyses met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[2] and DEQ determined that it was adequate to resolve maximum modeled impacts. A receptor grid extending out beyond 7,000 meters from the facility boundary was not necessary for these analyses because pollutants are emitted from relatively short stacks that will cause maximum impacts to be located very close to the source, typically at or very close to the ambient air boundary.

3.3.11 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

$H = S + 1.5L$, where:

- H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.
- S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.
- L = lesser dimension, height or projected width, of the nearby structure.

All Alta Mesa DJS 1-15 sources are below GEP stack height. Therefore, it is important to account for plume downwash caused by structures at the facility.

4.0 NAAQS Impact Modeling Results

4.1 Results for NAAQS Analyses

4.1.1 Submitted Analyses

A 1-hour and annual NO_2 cumulative NAAQS analysis was performed for the DJS 1-15 facility. Results of the impact analyses are provided in Table 9. Figure 1 shows 1-hour NO_2 design value impacts from the facility throughout the modeled domain. Figure 2 shows 1-hour NO_2 impacts in the immediate vicinity of the facility.

Table 9. RESULTS FOR SUBMITTED AIR IMPACT ANALYSES

Pollutant	Modeled Design Value Impact (μg/m³)[a]	Background Value (μg/m³)	Total Maximum Concentration (μg/m³)	NAAQS[b] (μg/m³)	Percent of NAAQS
1-hour NO_2	111.6	52.6	164.2	188	87
Annual NO_2	5.2	4.7	9.9	100	10

a. micrograms per cubic meter.
b. National Ambient Air Quality Standard

Design value impacts were primarily driven by impacts from the engine. The design value impact of the flare only was 10.1 μg/m^3 and the design value impact of the heaters only was 25.2 μg/m^3. The maximum design value impact was located several meters from the southeastern ambient air boundary, about 50 meters east, southeast of the engine stack and 16 meters south of the flare.

Emissions of CO were below DEQ Level 1 Modeling Thresholds, assuring that impacts are below the SIL. Air impact analyses of other criteria pollutants were not required because emissions were below levels defined as BRC.   Idaho Air Rules Section 203.02, requiring air impact analyses demonstrating compliance with NAAQS, is not applicable to pollutants having a project-emissions increase that is less than BRC levels, provided the project would have qualified for a BRC permitting exemption except for the emissions levels of another criteria pollutant exceeding the ton/year BRC threshold.

4.1.2 DEQ Sensitivity and Verification Analyses

DEQ performed both verification analyses and sensitivity analyses of impacts associated with the proposed DJS 1-15 project. Verification analyses assured that model output results, given the specified input parameters, are accurate and reproducible. Sensitivity analyses are performed to evaluate how sensitive model results are to changes in the input parameters, such as source exhaust flow rates, exhaust temperatures, etc.

Figure 1: Concentration Contours for 1-Hour NO2 Design Value Impacts

Background Concentrations not Included

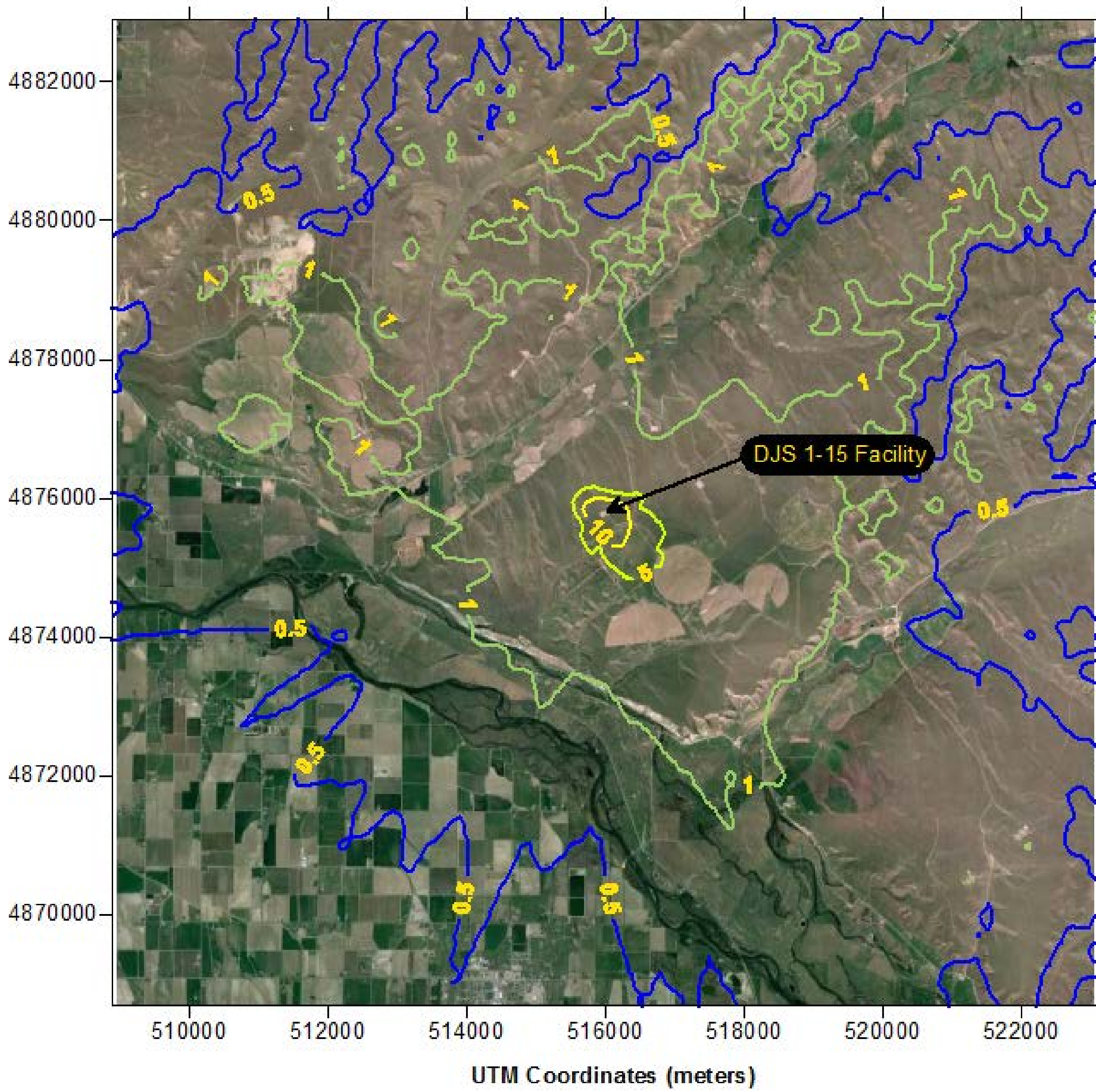
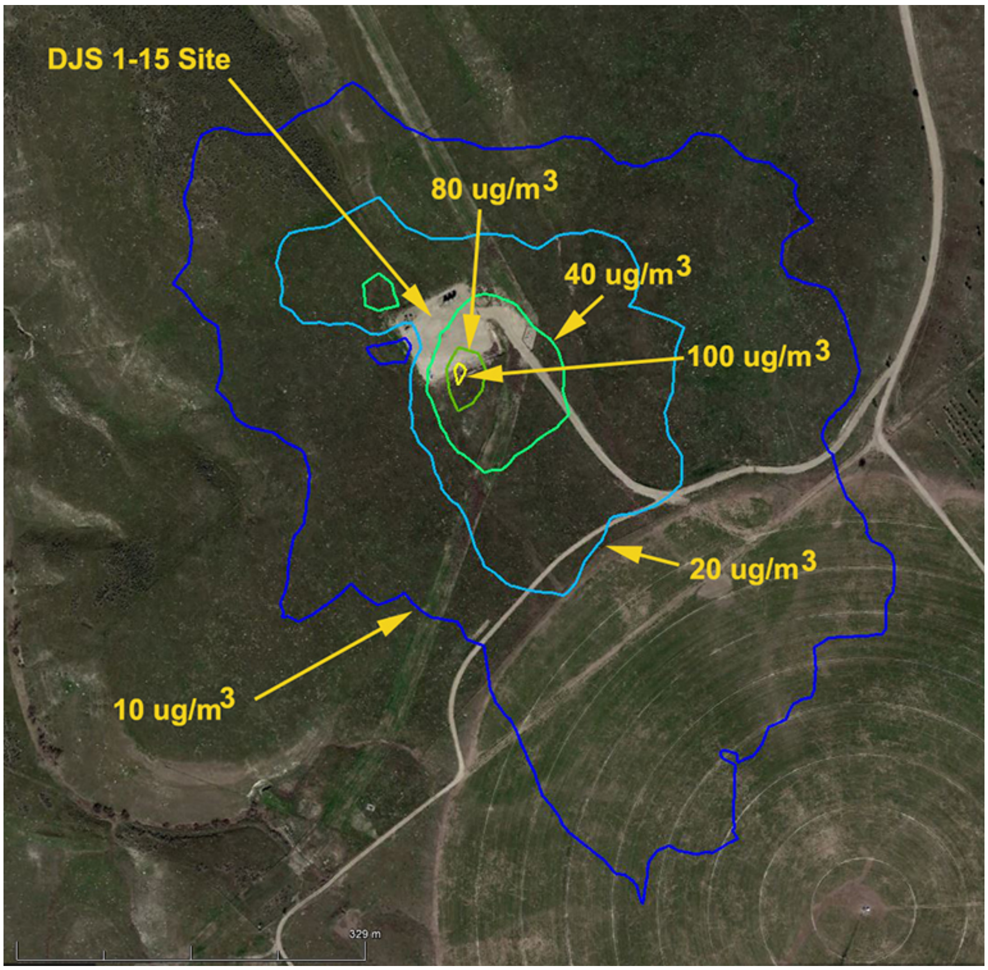


Figure 2: Concentration Contours for 1-Hour NO2 Design Value Impacts in the Immediate Vicinity of the DJS 1-15 Site



Verification Analysis Results

The 1-hour NO_2 design value result, equal to the highest value (of all receptors) of 8^{th} highest of maximum daily 1-hour modeled concentrations, from the DEQ verification analysis was 108.6 µg/m^3. This value is identical to that obtained from the analysis performed by W&A and submitted with the application. The location of the maximum impact was also identical to that of the submitted analysis.

Stack Parameter Sensitivity Analysis

DEQ increased the conservatism of modeled release parameters to evaluate the importance of assuring that "as-built" characteristics still assure NAAQS compliance if certain parameters vary slightly from those used in the impact analyses. Emissions rates were not adjusted.

The following are adjustments DEQ made to modeled release parameters for indicated sources:

- Engine: A flow rate of 70 percent of that used in the submitted analyses to account for operation at a reduced load.

- Engine: A larger stack diameter of 0.305 meters compared to 0.203 meters.

- Engine: With the flow and stack diameter adjusted as indicated above, the flow velocity was 16.6 meters/second. This is well below the flow velocity of 53.4 meters/second that was used in the submitted analyses.

- Flare: The EPA SCREEN3 method was used rather than the TCEQ method. As an additional level of conservatism, the effective stack height was not increased according to flame height calculations, as directed by the SCREEN3 method.

- Flare: The value for net heat released in the flare was half that used in the submitted analyses. This results in a lower total flow, a lower buoyancy flux, lower plume rise, and higher resulting ground-level concentrations in most instances.

- Heaters: DEQ used a combustion evaluation to calculate the exhaust volumetric flow rate for a 3.0 MMBtu/hour combustion source with a 300^o F exhaust temperature, and then adjusted the flow rate to half to account for a decreased operational rate (without a corresponding decrease in emissions). The result was a decrease in the exhaust flow rate from 22.3 meters/second to 11.7 meters/second.

The stack parameter sensitivity analyses for 1-hour NO_2 resulted in a design value impact of 121.7 µg/m^3. A total impact of 174.3 µg/m^3 was generated when the 52.6 µg/m^3 background value was added to the modeled result. Although this modeled impact is above the 164.2 µg/m^3 impact indicated by the submitted analysis, it is still well below the applicable 188 µg/m^3 NAAQS, especially considering the level of conservatism in numerous stack parameters.

Meteorological Data Sensitivity Analysis

DEQ performed a meteorological data sensitivity analysis to evaluate the need for a comparative assessment of data appropriateness between Langley Gulch data and Boise Airport data. The maximum 1-hour NO_2 modeled design value, using the 5-year Boise meteorological dataset, was 53.1 µg/m^3. This well below the 111.6 µg/m^3 design value obtained with the 1-year Langley Gulch meteorological dataset.

Reasons for the difference are uncertain, although use of a 5-year dataset tends to result in slightly lower design values because the 1-hour NO_2 design value is a multiyear average of the design value of each year.

The location of the maximum design value when using the Langley Gulch data was near the southeast ambient air boundary. The maximum design value when using Boise meteorological data was in the same general location, but 10 meters south. These locations are fairly consistent with the primary wind direction and each receptor location is somewhat elevated with respect to the base elevation at the location of the engine.

4.2 Results for TAPs Impact Analyses

Site-specific TAP impact analyses were not required for the DJS 1-15 facility because applicable facility-wide emissions of all TAPs are below ELs.

5.0 Conclusions

The information submitted with the PTC application, combined with DEQ air impact verification analyses, demonstrated to DEQ's satisfaction that emissions from the Alta Mesa DJS 1-15 facility will not cause or significantly contribute to a violation of any ambient air quality standard.

References

1. *Policy on NAAQS Compliance Demonstration Requirements.* Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *SCREEN3 Model User's Guide*. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Emission, Monitoring, and Analysis Division. Research Triangle Park, NC. EPA 454/B-95-004. September 1995.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard*. Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

PTC Fee Calculation

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Alta Mesa Services, LP - Kauffman 1-9**
Address:	**2.5 miles NE of Hwy 52 & Little Willow Rd.**
City:	**New Plymouth**
State:	**ID**
Zip Code:	**83661**
Facility Contact:	**Jennie Kent**
Title:	**Facilities Engineer**
AIRS No.:	**075-00023**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	0.5	0	0.5
SO_2	0.0	0	0.0
CO	8.0	0	8.0
PM10	19.3	0	19.3
VOC	25.1	0	25.1
TAPS/HAPS	1.3	0	1.3
Total:	0.0	0	**54.2**
Fee Due	**$ 5,000.00**		

Comments: