

Subchapter 10 Climate Change _

PROPOSED REGULATION ORDER

**Article 3: Greenhouse Gas Emission Standards for
Crude Oil and Natural Gas Facilities**

§ 95210. Purpose and Scope.

The purpose of this article is to establish greenhouse gas emission standards for crude oil and natural gas facilities identified in section 95211. This article is designed to serve the purposes of the California Global Warming Solutions Act, AB 32, as codified in sections 38500-38599 of the Health and Safety Code.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95211. Applicability.

(a) General Applicability

- (1) This article applies to any person that own or operates equipment listed in section 95213 located within California, including California waters, that is associated with facilities in the sectors listed below, regardless of emissions level:
 - (A) Onshore and offshore crude oil and natural gas production, processing, and storage;
 - (B) Natural gas underground storage; and,
 - (C) Natural gas transmission compressor stations.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95212. Definitions.

(a) For the purposes of this article, the following definitions apply:

- (1) "Air district or local air district" means the local Air Quality Management District or the local Air Pollution Control District.
- (2) "ARB" means the California Air Resources Board.
- (3) "Centrifugal compressor" means equipment that increases the pressure of natural gas by centrifugal action.

- (4) "Centrifugal compressor seal" means a wet or dry seal around the compressor shaft where the shaft exits the compressor case and that is designed to limit the amount of natural gas that can vent into the atmosphere.
- (5) "Circulation tank" means a tank used to circulate, store, or expel liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment.
- (6) "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- (7) "Condensate" means hydrocarbon and other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- (8) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure relief valve, pipe, seal fluid system, diaphragm, hatch, sight-glass, meter, or a reciprocating compressor rod packing or seal on units with less than 500 rated horsepower.
- (9) "Critical component" means any component which would require the shutdown of a critical process unit if these components were shutdown. These components must be identified by the owner or operator of the equipment and approved by the local air district.
- (10) "Equipment" means stationary or portable machinery, object, or contrivance covered by this article, as set out by sections 95211 and 95213 of this article, including vessels, circulation tanks, reciprocating and centrifugal compressors, pneumatic devices and pumps, production wells, components, or any combination thereof.
- (11) "Emissions" means the release of greenhouse gases, volatile organic compounds, toxic air contaminants, or other hydrocarbon gases into the atmosphere.
- (12) "Emulsion" means any mixture of crude oil, condensate, produced water, and varying amounts of natural gas.
- (13) "Facility" means any building, structure, facility or installation which emits any air contaminant directly or as a fugitive emission. "Building," "structure," "facility," or "installation" includes all pollutant emitting activities which:
 - (1) Are under the same ownership or operation, or which are owned or operated by entities which are under common control;

- (2) Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and,
- (3) Are located on one or more contiguous or adjacent properties.
- (14) "Flash" means emissions that vaporize from crude oil, condensate, or produced water when the liquids are subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to the earth's surface.
- (15) "Flash analysis testing" means sampling and laboratory procedures used for measuring the volume and composition of gas compressed into liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a gas-oil or gas-water ratio.
- (16) "Fugitive leak or fugitive emissions" means the unintended or incidental leak of emissions into the atmosphere.
- (17) "Inaccessible component" means any component located over fifteen feet above ground when access is required from the ground; or any component located over six (6) feet away from a platform when access is required from the platform.
- (18) "Leak detection and repair or LDAR" means the inspection of components to detect fugitive leaks of total hydrocarbon emissions and the repair of components with leaks above an allowable leak standard within a specified timeframe.
- (19) "Liquids unloading" means the venting of natural gas from a natural gas production well to remove liquids that accumulate at the bottom of the well and obstruct gas flow.
- (20) "Major leak" means the detection of total gaseous hydrocarbons in excess of 10,000 ppmv as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A).
- (21) "Major leak over 50,000 ppmv" means the detection of total gaseous hydrocarbons in excess of 50,000 ppmv as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A).
- (22) "Minor leak" means the detection of total gaseous hydrocarbons in excess of 1,000 ppmv as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A).

- (23) "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, of which its constituents include methane, carbon dioxide, and heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.
- (24) "Natural gas transmission compressor station" means all equipment and components associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines.
- (25) "Natural gas underground storage" means all equipment and components associated with the subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns.
- (26) "Offshore" means all marine waters located within the boundaries of the State of California.
- (27) "Onshore" means all lands located within the boundaries of the State of California.
- (28) "Operator" means the entity, including an owner, having operational control of components or equipment, including leased, contracted, or rented components and equipment to which this article applies.
- (29) "Owner" means the entity that owns components or equipment to which this article applies.
- (30) "Pneumatic device" means an automation device that uses natural gas or compressed air to maintain a process or pressure.
- (31) "Pneumatic pump" means a device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.
- (32) "Portable equipment" means designed and capable of being carried or moved from one location to another and resides at a location for less than 12 months. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.
- (33) "Primary vessel" means the first vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more crude oil or natural gas well and allows emissions to flash from the liquids to a headspace or to the atmosphere.
- (34) "Processing" means all activities associated with the separation or treatment of emulsion, crude oil, condensate, produced water, or natural gas into one or more component mixtures.

- (35) "Production" means all activities associated with the production or recovery of crude oil, condensate, or natural gas and includes well stimulation treatments.
- (36) "Produced water" means water recovered from an underground reservoir as a result of crude oil or natural gas production and which may be recycled or re-injected into an underground reservoir.
- (37) "Production well or well" means a boring in the Earth that is designed to bring crude oil, condensate, or natural gas to the surface.
- (38) "Reciprocating compressor" means equipment that increases the pressure of natural gas by positive displacement and by employing linear movement of a shaft driving a piston in a compression cylinder and powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.
- (39) "Reciprocating compressor rod packing" means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes into the atmosphere
- (40) "Reciprocating compressor seal" means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.
- (41) "Repair" means tightening or adjusting or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks to the atmosphere.
- (42) "Secondary vessel" means any vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from a primary vessel and allows emissions to flash from the liquids to a headspace or to the atmosphere. There may be more than one secondary vessel in a separation and tank system.
- (43) "Separator" means any pressurized or non-pressurized container constructed primarily of non-earthen materials used to separate emulsions of crude oil, condensate, natural gas, or produced water.
- (44) "Storage" means all activities associated with storing crude oil, condensate, produced water, natural gas, or emulsion.
- (45) "Sump" means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used to separate or store emulsions of crude oil, condensate, natural gas, or produced water.
- (46) "Tank" means any container constructed primarily of non-earthen materials used to circulate or store emulsion, crude oil, condensate, or produced water.

- (47) "Vapor collection system" means equipment and components installed on vessels including piping, connections, and flow-inducing devices used to collect and route emissions to a processing, sales gas, or fuel gas system; to an underground injection well; or to a vapor control device.
- (48) "Vapor control device" means destructive or non-destructive equipment used to process or control emissions.
- (49) "Vapor control efficiency" means the ability of a vapor control device to process or control emissions, expressed as a percentage, which can be estimated by calculation or by measuring the inlet and outlet emissions.
- (50) "Vented" means the intentional release of emissions into the atmosphere from equipment or processes described in this article.
- (51) "Vessel" means, for the purpose of this article, any tank, separator, or sump used to separate, store, or circulate emulsion, natural gas, crude oil, condensate, or produced water.
- (52) "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the underground crude oil or natural gas reservoir. Examples include hydraulic fracturing, acid fracturing, and acid matrix stimulation.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code

§ 95213. Standards.

The following standards apply to equipment in use in facilities listed in section § 95211 on and after **Month, Day, Year**:

[ARB staff currently intend that reporting and record-keeping provisions of the regulation, including requirements for flash testing, will be effective in January 1, 2017. Leak detection and repair and the reciprocating compressor strategies as well as control requirements for new sources will also be effective January 1, 2017. Provisions requiring retrofits of existing sources will be effective January 1, 2018, to provide time for covered entities to come into compliance.]

(a) *Primary and Secondary Vessels*

- (1) Owners or operators of crude oil, condensate, or produced water vessels without a vapor collection system installed on the primary and secondary vessels shall install a vapor collection system on the primary and secondary vessels as described in section 95213(c) or perform the following:

- (A) Conduct annual flash analysis testing of the crude oil, condensate, and produced water separated or stored by the primary and secondary vessels to determine the annual methane emission rate as follows:
1. Flash analysis testing shall be conducted in accordance with ARB Test Procedure *Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water* as described in Appendix A.
 2. Flash analysis testing is required at each primary vessel. Additional flash analysis testing may be conducted and the results averaged in order to determine representative testing.
 3. Sum the annual emission rates of methane as determined in section 95213(a)(1)(B)1 for the crude oil, condensate, and produced water.
 4. Report the results of flash analysis testing as described in section 95215(a)1.
 5. Owners or operators must demonstrate that the results of the flash analysis testing are representative of the liquids processed by the primary and secondary vessels. The ARB or the local air district may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.
- (B) Owners or operators of primary and secondary vessels with a measured annual emission rate greater than 10 metric tons per year of methane as determined in section 95213(a)(1)(B)(3) shall control the primary and secondary vessels as follows:
1. Vessels shall be equipped with leak free solid roofs and hatches; and,
 2. Vessels shall be controlled with use of a vapor collection system as described in section 95213(c).
- (C) Owners or operators of primary and secondary vessels without a vapor collection system and a measured annual emission rate less than or equal to 10 metric tons per year of methane as determined in section 95213(a)(1)(B)(3) shall conduct flash analysis testing and reporting annually, unless the owner or operator can demonstrate that the annual emission rate has not changed using three (3) consecutive years of test results; and,
1. If the owner or operator can successfully demonstrate to ARB or the local air district that the results of flash analysis testing have not

changed using three consecutive years of test data, flash analysis testing and reporting may be reduced to once every five (5) years thereafter; and,

2. Flash analysis testing and reporting shall be conducted at any time the annual crude oil or natural gas throughput of the primary and secondary vessels increases by more than ten (10) percent since the most recent flash analysis testing and reporting.

(b) Circulation Tanks for Well Stimulation Treatments

- (1) Circulation tanks used in conjunction with well stimulation treatments shall meet the following requirements:
 - (A) Control emission vapors from liquids prior to the circulation tank using a vapor collection and control system as described in section 95213(c); or,
 - (B) Circulation tanks shall be equipped with leak free solid roofs and hatches; and,
 - (C) Circulation tanks shall be controlled with use of a vapor collection system and control system as described in section 95213(c).

(c) Vapor Collection Systems

The following requirements apply to primary and secondary vessels and to circulation tanks for well stimulation treatments:

- (1) The vapor collection system shall direct the collected vapors to one of the following types of existing equipment or processes installed at the operation:
 - (A) Sales gas system; or,
 - (B) Fuel gas system; or,
 - (C) Underground injection well.
- (2) If the owner or operator can demonstrate to the satisfaction of the local air district that the collected vapors cannot be controlled according to one of the methods described in section 95213(c)(1), the vapor collection system shall direct the collected vapors to an existing vapor control device provided that any added vapors do not exceed the device's permitted emission limits.
- (3) The owner or operator must demonstrate to the satisfaction of the local air district that the collected vapors cannot be controlled according to one of the methods described in section 95213(c)(1) or 95213(c)(2) if they wish to use any of the methods described in section 95213(c)(4).

- (4) If the owner or operator can successfully demonstrate that the collected vapors cannot be controlled according to one of the methods described in 95213(c)(1) or 95213(c)(2), the owner or operator must apply for local air district approval to install one of the following:
 - (A) A vapor control device with at least 95% vapor control efficiency and which meets all applicable federal, state, and local air district requirements; or,
 - (B) If the system is located in an area classified as nonattainment with state or federal ozone standards, the owner or operator must apply for local air district approval to install one of the following types of equipment that meets all applicable federal, state, and local air district requirements:
 - 1. A non-destructive vapor control device that achieves at least 95% vapor control efficiency and does not result in emissions of nitrogen oxides (NOx) above local air district requirements; or,
 - 2. A vapor control device that achieves at least 95% vapor control efficiency and does not require supplemental fuel gas to operate or result in emissions of NOx above local air district requirements.
- (5) Vapor collection systems are allowed up to 14 calendar days per year for equipment breakdowns or maintenance provided that the local air district is notified within one (1) hour of the discovery of a system malfunction or if the system is intended to be taken out of service for scheduled maintenance. A time extension to make repairs not to exceed 14 calendar days may be granted by the local air district. The owner or operator is responsible for tracking the number of days per calendar year that the system is out of service and must provide a record of such activity at the request of the local air district.
- (6) Vapor collection system shutdowns that result from utility power outages or emergencies are not subject to enforcement action provided the system resumes normal operation as soon as normal utility power is restored.

(d) Reciprocating Natural Gas Compressors at or Below 500 Rated Horsepower

- (1) Each compressor shall collect the rod packing or seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device; or,
- (2) Each compressor shall provide a clearly identified access port for making rod packing or seal vent emission measurements; and,
- (3) Compressor rod packing or seal vents shall be measured quarterly for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated

as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A); and,

- (4) Compressor rod packing or seal vents with a measured total hydrocarbon concentration above the following standards shall be repaired within the time period specified unless a more stringent leak concentration or more stringent repair time period is required by the local air district:
 - (A) Rod packing or seal vents with a measured total hydrocarbon concentration above 1,000 ppmv but below 10,000 ppmv shall be successfully repaired or the unit removed from service within seven (7) calendar days. A time extension not to exceed seven (7) calendar days may be granted by ARB or the local air district.
 - (B) Rod packing or seal vents with a measured total hydrocarbon concentration above 10,000 ppmv shall be successfully repaired or the unit removed from service within three (3) calendar days. A time extension not to exceed two (2) calendar days may be granted by ARB or the local air district.
 - (C) Rod packing or seal vents with a measured total hydrocarbon concentration above 50,000 ppmv shall be successfully repaired or removed from service within two (2) calendar days.

(e) Reciprocating Natural Gas Compressors over 500 Rated Horsepower

- (1) Each compressor shall collect the rod packing or seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device; or,
- (2) Each compressor shall provide a clearly identified access port for making individual rod packing or seal emission flow rate measurements; and,
- (3) Each individual compressor rod packing or seal shall be measured annually during normal operation to determine the rod packing or seal emission flow rate determined by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); and,
- (4) An individual rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute shall be successfully repaired or the unit removed from service within 14 calendar days unless a more stringent flow rate or more stringent repair time is required by the local air district. A time extension not to exceed 14 calendar days may be granted by ARB or the local air district.

(f) Centrifugal Natural Gas Compressors

- (1) Centrifugal natural gas compressor seal vents shall be controlled for vented emissions according to one of the following methods:
 - (A) Use a dry seal system; or,
 - (B) Collect the wet seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device.

(g) Pneumatic Devices and Pumps

- (1) Pneumatic devices that are designed to continuously vent natural gas during normal operation shall not vent natural gas to the atmosphere. Alternatively, they must meet one of the following requirements:
 - (A) Collect the vented natural gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device; or,
 - (B) Use compressed air to operate.
- (2) Intermittent leak pneumatic devices that are designed to vent natural gas only when actuated shall not leak when idle.
- (3) Pneumatic pumps shall meet one the following requirements:
 - (A) Collect vented natural gas used to power the pump with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device; or,
 - (B) Use compressed air to operate.

(h) Liquids Unloading of Natural Gas Production Wells

- (1) The following requirements apply to natural gas wells that are vented to remove liquids that accumulate at the bottom of the production well and inhibit gas flow:
 - (A) Collect the vented natural gas used to remove accumulated liquids using a vapor collection system as described in section 95213(c); or,
 - (B) Measure the volume of natural gas vented to remove the accumulated liquids by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) and report the results to ARB; or,

- (C) Calculate the volume of natural gas vented to remove the accumulated liquids using the Liquid Unloading Calculation listed in Appendix B and report to the results to ARB.

(i) *Leak Detection and Repair*

- (1) Leak detection and repair requirements do not apply to the following unless required by the local air district:
 - (A) Components that are buried below ground.
 - (B) One-half inch and smaller stainless steel tube fittings including those used for instrumentation.
 - (C) Components incorporated in lines operating under negative pressure.
 - (D) Components and piping located downstream from the point where crude oil or natural gas transfer of custody occurs, including components and piping located outside the location boundaries of natural gas compressor stations and underground storage operations.
 - (E) Temporary components or equipment used for general maintenance purposes and used less than 300 hours per calendar year.
 - (F) Components which are unsafe to monitor when conducting EPA Method 21(40 CFR 60, Appendix A) measurements and as documented in a safety manual or policy and with approval of the local air district.
- (2) Except as provided in section 95213(i)(1), components containing natural gas in source categories listed in section 95211 shall be inspected according to one of the following methods and at the frequency specified unless other monitoring methods or a more stringent inspection time period is required by the local air district:
 - (A) Annually, inspect and measure components for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A); or,
 - (B) Quarterly, inspect components using an optical gas imaging instrument that detects the presence of hydrocarbon vapors or meets criteria specified in 40 CFR part 60 for optical gas imaging instruments; and,
 - 1. Within two (2) calendar days of initial leak detection of a component, or within 14 calendar days of initial leak detection of an inaccessible component, measure the leak for total hydrocarbon concentration in

units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

- (3) Any component measured in accordance with EPA Reference Method 21(40 CFR 60, Appendix A) and is found to have a total hydrocarbon concentration above the following standards shall be repaired within the time period specified unless a more stringent leak standard or a more stringent repair time period is required by the local air district:
 - (A) Fugitive leaks with a measured total hydrocarbon concentration above 1,000 ppmv but not greater than 10,000 ppmv shall be successfully repaired or removed from service within seven (7) calendar days of initial leak detection. A time extension to make repairs not to exceed seven (7) calendar days may be granted by the local air district.
 - (B) Fugitive leaks with a measured total hydrocarbon concentration above 10,000 ppmv shall be successfully repaired or removed from service within three (3) business days of initial leak detection. A time extension to make repairs not to exceed two (2) calendar days may be granted by the local air district.
 - (C) Fugitive leaks with a measured total hydrocarbon concentration above 50,000 ppmv shall be successfully repaired within two (2) calendar days.
 - (D) Critical components found above the minor leak threshold and that are technically infeasible to repair 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, shall be repaired to minimize leakage to the maximum extent possible within one (1) hour of detection and the repair of such components shall be completed by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.
- (4) Upon detection of a component that is measured above the standards specified in section 95813 (i)(3), the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the component until all of the following conditions are met:
 - (A) The leaking component has been repaired or replaced; and,
 - (B) The component has been re-inspected and determined to be leak free when measured in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95214. Record Keeping Requirements.

- (a) Owners or operators of equipment in source categories listed in section 95211 are required to maintain, and make available upon request by ARB or the local air district, records identified below:

Primary and Secondary Vessels

- (1) Maintain a record of flash analysis testing including a diagram of the primary and secondary vessels with the sampling location, laboratory reports, and accompanying information as described in Appendix C, Table 1.

Reciprocating Natural Gas Compressors

- (2) For a minimum of five (5) years, maintain a record identifying rod packing or seal emission measurements and maintenance activity for each compressor at or below 500 rated horsepower as described in Appendix C, Table 2.
- (3) For a minimum of five (5) years, maintain a record of rod packing emission flow rate measurements and maintenance activity for each compressor over 500 rated horsepower as described in Appendix C, Table 2.

Liquids Unloading of Natural Gas Production Wells

- (4) For a minimum of five (5) years, maintain a record of the volume of natural gas that is vented to remove accumulated liquids for each production well that is vented and not connected to a vapor collection system as described in Appendix C, Table 3 ; and,
- (5) For a minimum of five (5) years, maintain a record of equipment installed in each production well and designed to automatically unload liquids (e.g., plunger-lift system, velocity tubing, soap solution) for each production well that is vented to remove accumulated liquids and is not connected to a vapor collection system as described in Appendix C, Table 3.

Leak Detection and Repair

- (6) For a minimum of five (5) years, maintain a record of leak detection and repair activities that include the following:
- (A) Date, name, and location of operation inspected.
- (B) Type of component found leaking.

- (C) Measured total hydrocarbon concentration (ppmv).
- (D) Date of repair or date(s) of attempted repair.
- (E) Measured total hydrocarbon concentration (ppmv) after leak is repaired.
- (F) Total number of components inspected, total number of leaks identified, and percentage of leaking components.
- (G) Current record identifying all components awaiting repair.
- (H) Type of leak detection instrument(s) used to conduct the inspection including date and time of instrument calibration(s) as required by the instrument manufacturer.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95215. Reporting Requirements.

- (a) Owners or operators of equipment in source categories listed in section 95211 are required to information identified below within the timeframes specified:

Primary and Secondary Vessels

- (1) Within 90 days of performing flash analysis testing or within 90 days after subsequent testing, report the results of flash analysis testing, including a diagram of the primary and secondary vessels with the sampling location, the laboratory reports, and accompanying information as described in Appendix B, Table 1 to the local air district enforcing the requirements of this regulation and to the ARB using the contact information provided in section 95215(b).

Liquids Unloading of Natural Gas Production Wells

- (2) Annually, report the volume of natural gas that is vented to remove accumulated liquids for each production well that is vented and not connected to a vapor collection system as described in Appendix C, Table 3 to the ARB using the contact information provided in section 95215(b); and,
- (3) Annually, report equipment installed in each production well and designed to automatically unload liquids (e.g., plunger-lift system, velocity tubing, soap solution) for each production well that is vented to remove accumulated liquids and is not connected to a vapor collection system as described in Appendix C, Table 3 to the ARB using the contact information provided in section 95215(b).

Leak Detection and Repair

- (4) Annually, report a summary of results of leak detection and repair activities as described in Appendix C, Table 4 to the ARB using the contact information provided in section 95215(b).

- (b) Reports may be e-mailed electronically to ARB with the subject line "O&G GHG Regulation Reporting" to oil&gas@arb.ca.gov or mailed to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95216. Implementation.

(a) Implementation by ARB and by the Local Air Districts

- (1) The requirements of this article are provisions of state law that apply to the owners and operators of equipment in the categories listed in section 95211 of this Article and are enforceable by both ARB and air districts in which the equipment is located. An owner or operator of equipment subject to this article must pay any fees assessed by an air district for the purposes of recovering the air district's cost of implementing and enforcing the requirements of this article. Any penalties secured by an air district as the result of an enforcement action that it undertakes may be retained by the air district.
- (2) The Executive Officer, at his or her discretion, may enter into an agreement or agreements with any air district to further define implementation and enforcement processes, including arrangements for information sharing between ARB and air districts, relating to this article.
- (3) Implementation and enforcement of the requirements of this article by an air district may in no instance result in a standard, requirement, or prohibition less stringent than provided for by this article, as determined by the Executive Officer. The terms of any air district permit relating to this article do not alter the terms of this article, which remain as separate requirements for all sources subject to this article.
- (4) Implementation and enforcement of the requirements of this article by an air district, including inclusion or exclusion of any of its terms within any air district

permit or registration of a facility with an air district or ARB, does not in any way waive or limit ARB's authority to implement and enforce upon the requirements of this Article. A facility's permitting or registration status also in no way limits the ability of air districts to enforce the requirements of this article.

(b) Requirements for Covered Entities

(1) Local Air District Permitting Requirements

- (A) Owners or operators of facilities with equipment regulated by this article and who are required to hold local air district permits for those facilities shall ensure, on the timeline set out in this subsection, that their local air district permits for those facilities ensure that all equipment at each facility is in compliance with this article. Any combination of local air district permits that, individually or collectively, are shown to ARB's satisfaction to ensure the compliance of all of an owner or operator's equipment subject to this article satisfies this requirement.
- (B) For existing facilities with equipment subject to this article, owners or operators of those facilities must comply with this subsection for each such facility by the next air district permit renewal date for the facility, or by **[Month, Day Year]**, whichever is sooner.
- (C) For new facilities installed after **[Month, Day, Year]** with equipment subject to this article, owners or operators of this equipment must ensure that all local air district permits for those facilities include terms that ensure compliance with this article.
- (D) If, after the effective date of this article, any air district amends or adopts permitting rules that result in additional facilities with equipment regulated by this article becoming subject to local air district permitting, then this subsection applies to those newly-covered facilities. Owners or operators of those facilities must ensure that any applicable local air district permits for those facilities ensure compliance with this article within two years of the effective date of the local air district rule amendment that resulted in the facility being covered for local air district permitting purposes.

(2) Reporting and Registration Requirements for Facilities Not Subject to an Air District Permitting Program

- (A) Owners or operators of facilities with equipment covered by this article which are not included in a local air district permitting program shall register the facility by reporting the following information by **[Month, Day, Year]**. The information shall be reported to ARB unless the relevant local air district has established a registration program that collects at least the following information.

1. The owner or operator's name and contact information for the equipment covered by this article.
 2. A description of the crude oil or natural gas facility where the equipment is located.
 3. A description of all equipment covered by this article located at the facility which shall include the following:
 - (a) The number of crude oil or natural gas wells at the facility.
 - (b) A list of all tanks and separators at the facility, including the size of each tank and separator in units of barrels.
 - (c) The annual crude oil, natural gas, and produced water throughput of the facility.
 - (d) A list of all reciprocating and centrifugal natural gas compressors at the facility, including the manufacturer's horsepower rating for each compressor.
 - (e) A count of all pneumatic devices and pumps at the facility.
- (B) Updates to these reports, recording any changes in this information, must be filed with ARB, or, as relevant, with the air district no later than **[Month, Day]** each year if the owner or operator has installed or removed any equipment covered by this article at its facility.
- (3) Owners or operators of equipment subject to this article must comply with all the requirements of sections 95211, 985212, 95213, 95214, 95215, and 95217 of this article, regardless of whether or not they have secured local air district permits or registered the equipment with ARB or the local air district where the facility is located.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39603 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600, 40701, 41511, 42300, 42301, and 42311, Health and Safety Code.

§ 95217. Enforcement.

- (a) Failure to comply with the requirements of this article at each individual piece of equipment subject to this article constitutes a single, separate, violation of this article.
- (b) Each day, or portion thereof, that an owner or operator is not in full compliance with the requirements of this article is a single, separate, violation of this article.

(c) Failure to submit any report required by this article shall constitute a single, separate violation of this article for each day or portion thereof that the report has not been received after the date the report is due.

(d) Failure to retain and failure to produce any record that this article requires to be retained or produced shall constitute a single, separate violation of this article for each day or portion thereof that the record has not been retained or produced.

NOTE: Authority cited: Sections 38510, 38562, 38580, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95218. No Preemption of More Stringent Air District or Federal Requirements

This regulation does not preempt any more stringent requirements imposed by any Air District. Compliance with this article does not excuse noncompliance with any Federal regulation. The Executive Officer retains authority to determine whether an Air District requirement is more stringent than any requirement of this Article.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95219. Severability

Each part of this article is deemed severable, and in the event that any part of this article is held to be invalid, the remainder of the article shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

Appendix A

Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water

California Environmental Protection Agency
Air Resources Board

**Test Procedure for Determining Annual Flash Emission Rate of Methane
from Crude Oil, Condensate, and Produced Water**

1. PURPOSE AND APPLICABILITY

In crude oil and natural gas production, flash emissions may occur when gases vaporize from crude oil, condensate, or produced water due to a decrease in liquid pressure, such as when the liquids are transferred from an underground reservoir to a lower pressure vessel on the earth's surface. This procedure is used for determining the annual flash emission rate from primary and secondary vessels used to separate or store crude oil, condensate and produced water. The laboratory methods required to conduct this procedure are used to measure methane and other gaseous compounds.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

This procedure is conducted by gathering one sample of crude oil or condensate and one sample of produced water from a pressurized primary separator located upstream of any vessel or location where flashing may occur. Samples must be taken from a pressurized primary separator and gathered according to the sampling methodologies described in this procedure. If a pressurized primary separator is not available, sampling shall be conducted using a portable pressurized separator just prior to the first atmospheric vessel to gather samples in accordance with this procedure.

Two sampling methods are specified for collecting liquid samples while maintaining a positive pressure in the sample cylinder to prevent flashing during the sample collection procedure. The first method requires a double valve cylinder filled with a non-reactive liquid that is immiscible with the sample liquid collected. The second requires a cylinder equipped with a pressurized piston. Either method may be used for this procedure and must be used as specified for the type of sample liquid gathered.

The laboratory methods specified for this procedure are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (EPA), and Gas Processor Association (GPA) methods and standards. These laboratory methods measure the volume and composition of gases that flash from the liquids, including a Gas-Oil or Gas-Water Ratio, as well as the molecular weight and weight percent of the gaseous compounds. The laboratory results are combined with the vessel throughput to calculate the mass of emissions that are flashed from the liquids per year.

3. DEFINITIONS

For the purposes of this procedure, the following definitions apply:

- 3.1** "Air district or local air district" means the local Air Quality Management District or the local Air Pollution Control District.
- 3.2** "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.
- 3.3** "ARB" means the California Air Resources Board.
- 3.4** "Condensate" means hydrocarbon and other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- 3.5** "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- 3.6** "Double valve cylinder" means a metal cylinder equipped with valves on either side for gathering crude oil, condensate, or produced water samples.
- 3.7** "Emissions" means the release of methane, volatile organic compounds, toxic air contaminants, or other hydrocarbon gases into the atmosphere.
- 3.8** "Flash" means emissions that vaporize from crude oil, condensate, or produced water when the liquids are subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to the earth's surface.
- 3.9** "Gas-Oil Ratio (GOR)" means a measurement used to describe the volume of gas that is flashed from a barrel of crude oil or condensate.
- 3.10** "Gas-Water Ratio (GWR)" means a measurement used to describe the volume of gas that is flashed from a barrel of produced water.
- 3.11** "Operating pressure" means the working pressure of the pressurized primary separator from which a sample is gathered.
- 3.12** "Operating temperature" means the working temperature of the pressurized primary separator from which a sample is gathered.

- 3.13** "Percent water cut" means the percentage of water by volume, of the total emulsion throughput as measured using ASTM D-4007. The percent water cut is expressed as a percentage.
- 3.14** "Piston cylinder" means a metal cylinder containing an internal pressurized piston for gathering crude oil, condensate, or produced water samples.
- 3.15** "Portable pressurized separator" means a sealed metal vessel used for separating and measuring crude oil or condensate and produced water, and may allow for metering natural gas volume. The vessel is used to separate the liquids while they continuously flow through the vessel at steady state conditions upstream of any vessel or location where flashing may occur.
- 3.16** "Pressurized primary separator" means the first vessel that receives crude oil, condensate, or produced water from one or more crude oil or natural gas wells and is pressurized to at least five (5) pounds per square inch gauge pressure and allows liquids to continuously flow through the unit at steady state conditions. The pressurized primary separator must be located upstream of any vessel or location where flashing may occur.
- 3.17** "Primary vessel" means the first separator or tank that receives crude oil, condensate, or produced water from one or more crude oil or natural gas wells.
- 3.18** "Produced water" means water recovered from an underground reservoir as a result of crude oil or natural gas production and which may be recycled or re-injected into an underground reservoir.
- 3.19** "Secondary vessel" means any vessel that receives crude oil, condensate, or produced water from a primary vessel. There may be more than one secondary vessel in a separation and tank system.
- 3.20** "Separator" means any pressurized or non-pressurized container constructed primarily of non-earthen materials used to separate emulsions of crude oil, condensate, natural gas, or produced water.
- 3.21** "Tank" means any container constructed primarily of non-earthen materials used to circulate or store emulsion, crude oil, condensate, or produced water.
- 3.22** "Throughput" means the average volume of crude oil, condensate, or produced water processed by a vessel in units of barrels per day.
- 3.23** "Vessel" means any tank or separator used to separate, store, or circulate crude oil, condensate, or produced water.

4. BIASES AND INTERFERENCES

- 4.1** The sampling method used to gather a liquid sample will have an impact on the final results reported. Liquid samples shall be gathered in accordance with the sampling procedures specified in this procedure.
- 4.2** The vessel used to gather a liquid sample will have an impact on the final results reported. Liquid samples shall be gathered from a pressurized primary or portable separator as specified in this procedure.
- 4.3** Collecting liquid samples from an empty double valve cylinder without displacing an inert liquid from the cylinder will allow gases to flash from the cylinder and bias the final results reported. Liquids samples gathered using a double valve cylinder shall be gathered as specified in this procedure.
- 4.4** Displacing liquids that are reactive and not immiscible with the sample liquid to be collected from a double valve cylinder can result in gas composition or volume errors and affect the reported results. Displacement liquids shall be pre-tested by a laboratory to verify that the liquid is non-reactive and immiscible with the sample liquid to be collected.
- 4.5** Non-calibrated equipment including pressure or temperature gauges will bias the final results reported. All pressure and temperature measurements shall be conducted with calibrated gauges as specified in this procedure.
- 4.6** Conducting laboratory procedures other than those specified in this procedure will bias the final results reported. All laboratory methods shall be conducted as specified in this procedure.

5. EQUIPMENT SPECIFICATIONS

- 5.1** A pressure gauge capable of measuring liquid pressure less than 50 pound per square inch gauge pressure within +/-10% accuracy.
- 5.2** A pressure gauge capable of measuring liquid pressure greater than 50 pounds per square inch gauge pressure within +/- 5% accuracy.
- 5.3** A temperature gauge capable of reading liquid temperature within +/- 2°F and within a range of 32°F to 200°F.
- 5.4** A graduated cylinder capable of measuring liquid in one (1) milliliter increments with at least the same capacity as the double valve cylinder used for liquid sampling.

- 5.5** A portable pressurized separator capable of measuring crude oil or condensate and produced water throughput within +/- 1 barrel per hour accuracy.

6. TEST EQUIPMENT

- 6.1** A double valve cylinder or a piston cylinder.
- 6.2** A graduated cylinder for use with double valve cylinder.
- 6.3** A waste container suitable for capturing and disposing sample liquid.
- 6.4** High-pressure rated metal components and control valves that can withstand the temperature and pressure of the pressurized primary vessel being sampled.
- 6.5** Pressure gauges with minimum specifications listed in section 5.
- 6.6** A temperature gauge with minimum specifications listed in section 5.
- 6.7** A portable pressurized separator capable of measuring crude oil or condensate and produced water throughput while allowing liquids to continuously flow through the vessel with minimum specifications listed in section 5.

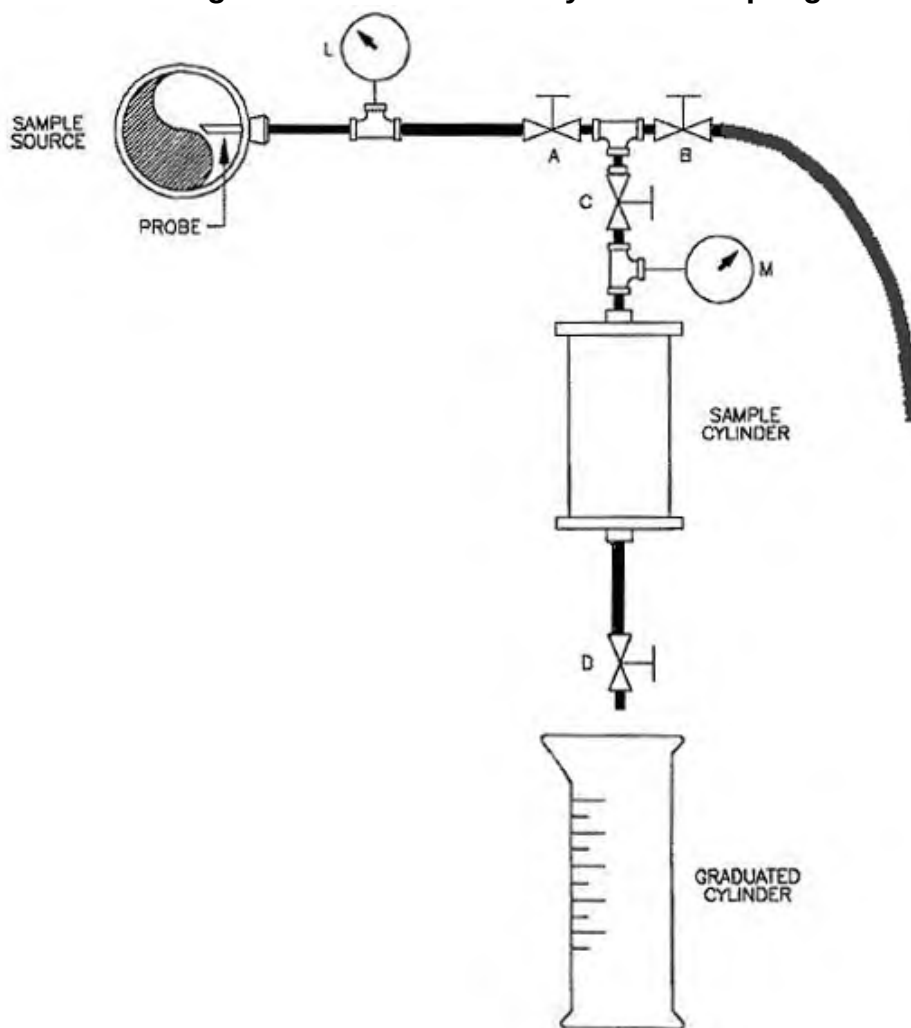
7. DATA REQUIREMENTS

- 7.1** For each pressurized primary or portable separator sampled, the sampling technician shall be provided with the following information which shall be recorded on the sampling cylinder identification tag and Form 1 at the time of liquid sampling:
 - (a) The separator identification number or description; and,
 - (b) The separator temperature and pressure if available; and
 - (c) Crude oil or condensate throughput; or,
 - (d) Produced water throughput; and,
 - (e) Percent water cut; and,
 - (f) Crude oil storage tank temperature if heated; and,
 - (g) Gas volume of three phase separator if available; and,
 - (h) Number of wells in the separator and tank system; and,
 - (i) Days of operation per year.

8. DOUBLE VALVE CYLINDER SAMPLING METHOD

- 8.1 Fill the double valve cylinder with non-reactive liquid that is immiscible with the liquid to be collected to prevent flashing within the cylinder and to prevent the displacement liquid from mixing or attaining homogeneity with the sample liquid.
- 8.2 Locate the pressurized primary separator for sampling and verify it is pressurized to at least 10 psig and located upstream of any vessel or location where flashing may occur. Install a portable pressurized separator if no pressurized primary separator is available.
- 8.3 Record the information specified in section 7 on the cylinder identification tag and on Form 1.

Figure 1: Double Valve Cylinder Sampling Train

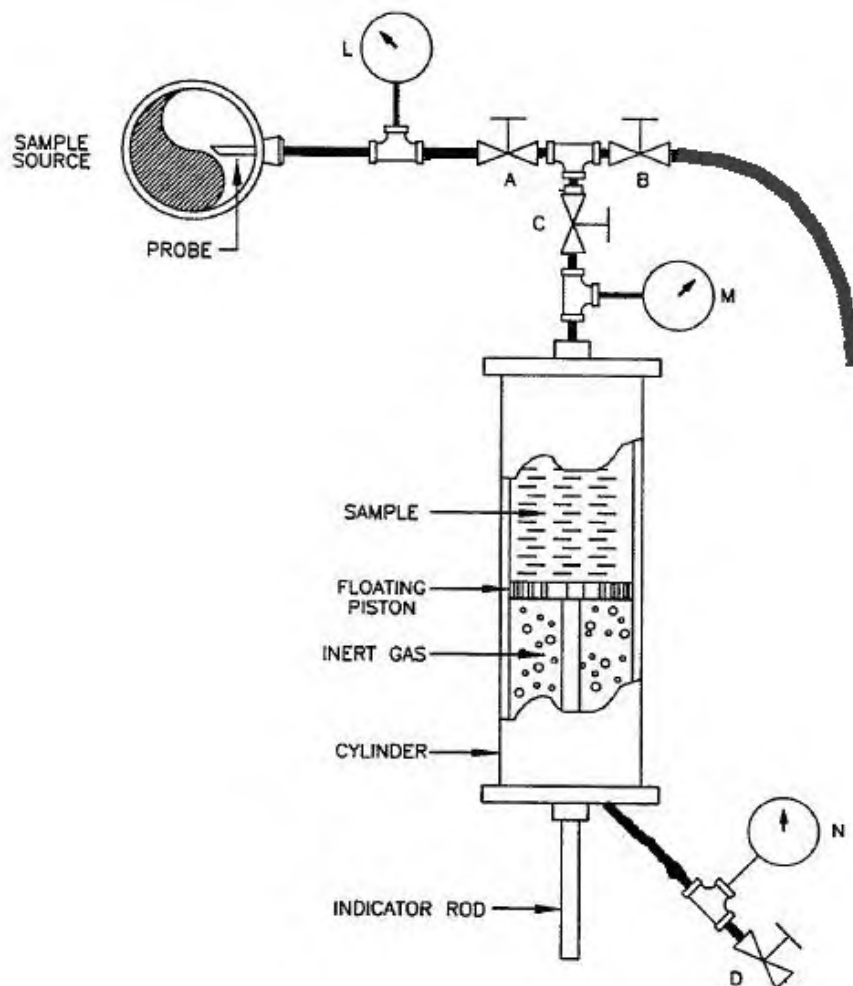


- 8.4** Locate the sampling port(s) for gathering liquid samples.
- 8.5** Connect the sampling train as illustrated in Figure 1 to the sampling port on the separator. Bushings or reducers may be required.
- 8.6** Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.
- 8.7** Prepare for sampling: Orient the cylinder in the vertical position with the inlet valve at the top for displacing crude oil, or with the inlet valve at the bottom for displacing producing water. For gathering crude oil samples: With valve B closed and valve A open, slowly open valve C to the full open position and place the outlet of valve D into the graduated cylinder. Invert the cylinder valve configuration for collecting produced water throughout the remainder of this sampling method.
- 8.8** Gather liquid sample: Slowly open valve D to allow a slow displacement of the deionized water at a rate of 180 milliliters per minute (3 drips per second) to prevent the sample liquid from flashing inside the cylinder. Continue displacing the deionized water until 95 percent +/- 0.05 percent of the deionized water is displaced from the sample cylinder by measuring the displaced deionized water with the graduated cylinder, and then close valve D.
- 8.9** Record the liquid temperature and pressure from gauges L and M immediately after or during sampling to allow the gauges to stabilize and provide for accurate measurements.
- 8.10** Record the double valve cylinder volume and the volume of liquid sampled on the cylinder identification tag and on Form 1.
- 8.11** Remove sampling train: With valve D closed, close valves A and C. Place the outlet of valve B into the waste container and slowly open valve B to purge liquid from the sampling train. Close valve B and disconnect the sampling train from the sample port on the vessel.
- 8.12** Disconnect the sample cylinder from the sampling train and verify that both valves on the sampling cylinder are sealed.
- 8.13** Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 8.14** Transport the cylinder to the laboratory for conducting the laboratory methods specified in section 12.

9. PISTON CYLINDER SAMPLING METHOD

- 9.1 Locate the pressurized primary separator for sampling and verify it is pressurized to at least 10 psig and located upstream of any vessel or location where flashing may occur. Install a portable pressurized separator if no pressurized primary separator is available.
- 9.2 Record the information specified in section 7 on the cylinder identification tag and on Form 1.
- 9.3 Locate the sampling port(s) for gathering liquid samples.
- 9.4 Connect the sampling train as illustrated in Figure 2 to the sampling port on the separator. Bushings or reducers may be required.

Figure 2: Piston Cylinder Sampling Train



- 9.5** Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.
- 9.6** Prepare for sampling: With valve B closed and valve A open, slowly open valve C to the full open position, then slowly open valve D until the pressure indicated on Gauge N is equal to Gauge M.
- 9.7** Gather liquid sample: Slowly open Valve D to allow liquid to enter the piston cylinder at a rate of 180 milliliters per minute until 95 percent $\pm$ 0.05 percent of the cylinder is filled with liquid and then close valve D.
- 9.8** Record the liquid temperature and pressure from gauges L and M immediately after or during sampling to allow the gauges to stabilize and provide for accurate measurements.
- 9.9** Record the cylinder volume and volume of liquid sampled on the cylinder identification tag and on Form 1.
- 9.10** Remove sampling train: With valve D closed, close valves A and C. Place the outlet of valve B into the waste container and slowly open valve B to purge all liquid from the sampling train. Close valve B and disconnect the sampling train from the sample port on the vessel.
- 9.11** Disconnect the sample cylinder from the sampling train and verify that both valves on the sampling cylinder are sealed.
- 9.12** Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 9.13** Transport the cylinder to the laboratory for conducting the laboratory methods as specified in section 12.

10. CALCULATING RESULTS

The following calculations are performed in conjunction with the information specified in section 7 and the laboratory reports specified in section 12. The same calculations are used for crude oil, condensate, and produced water.

10.1 Calculate the volume of gas flashed from the liquid per year using the Gas Oil or Gas Water Ratio supplied by the laboratory as follows:

$$Ft^3 / Year = (G) \left(\frac{Barrels}{Day} \right) \left(\frac{Days}{Year} \right) \quad \text{Equation 1}$$

Where:

$Ft^3/Year$ = standard cubic feet of gas produced per year

G = Gas Oil or Gas Water Ratio (from laboratory analysis)

Barrels/Day = barrels per day of liquid (Form 1)

Days/Year = days of operation per year (Form 1)

10.2 Convert the gas volume to pounds as follows:

Equation 2

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year} \right) \left(\frac{gram}{gram - mole} \right) \left(\frac{gram - mole}{23.690 l} \right) \left(\frac{28.317 l}{Ft^3} \right) \left(\frac{lb}{454 grams} \right)$$

Where:

$Mass_{Gas} / Year$ = pounds of gas per year

$Ft^3/Year$ = cubic feet of gas produced per year (Equation 1)

Gram/Gram-Mole = Molecular weight (from laboratory analysis)

23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60°F

10.3 Calculate the annual mass of methane as follows:

$$Mass_{Methane} / Year = \left(\frac{WT\% \text{ Methane}}{100} \right) \left(\frac{Mass_{Gas}}{Year} \right) \left(\frac{metric ton}{2205 lb} \right) \quad \text{Equation 3}$$

Where:

$Mass_{Methane} / Year$ = metric tons of methane

$Mass_{Gas} / Year$ = pounds of gas per year (Equation 2)

WT% Methane = Weight % of methane (lab analysis)

11. REPORTING RESULTS

11.1 The results of this procedure are used to report annual methane flash emission rates to the Air Resources Board as well as the local air district if the local district is enforcing these testing requirements. The following information shall be provided when test results are submitted:

- (a) A copy of Form 1; and,
- (b) A copy of all laboratory reports; and,
- (c) A copy of calculations with annual methane flash emission rate; and,
- (d) A sketch or diagram of all vessels in the separator and tank system including the location from where samples were taken.

11.2 Reports may be e-mailed electronically to ARB with the subject line "O&G GHG Regulation Reporting" to oil&gas@arb.ca.gov or mailed to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814

12. LABORATORY METHODS

12.1 Flash Liberation Test Equipment Requirements

- (a) Liquid samples must be heated to the same temperature measured at the time of sampling and allowed to cool at a rate no greater than five (5) degrees Fahrenheit per minute and then held at constant storage temperature or ambient temperature as noted on Form 1.
- (b) The laboratory apparatus must be temperature and pressure controlled while precisely measuring liquid and gas volume, temperature, and pressure.
- (c) The laboratory apparatus must be capable of collecting the liberated flash gas for gas chromatography analysis.
- (d) The liberated flash gas volume may decrease during sample cooling. The laboratory apparatus or procedure used for conducting flash liberation gas volume measurements shall account for gas volume shrinkage.
- (e) Additional sample preparation guidance can be found in GPA 2174, GPA 2261 and GPA 2177.

12.2 Flash Liberation Test Requirements

- (a) Heat the sample to the temperature recorded on Form 1 and allow to stabilize for at least 30 minutes.
- (b) After the temperature has stabilized, begin the flash liberation volume measurement and adjust the temperature to the storage or ambient temperature recorded on Form 1.
- (c) Allow the sample to cool at a rate no greater than five (5) degrees Fahrenheit per minute while collecting the flash liberation gas and monitoring gas pressure and accounting for volume shrinkage.
- (d) Allow the sample to cool to the storage temperature or ambient temperature recorded on Form 1 for a minimum of 30 minutes.
- (e) Continue measuring the flash liberation gas volume until the gas pressure stabilizes at ambient pressure and no changes in pressure are evident for at least 30 minutes.
- (f) After the flash liberation test is completed, drain the liquid from the sample cylinder into an appropriate graduated cylinder and record total liquid volume and volume fractions (for example, 300ml total volume, 285 ml crude oil, 15 ml water).

12.3 Analytical Laboratory Methods and Requirements

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water. All methods and quality control requirements shall be conducted as specified in each method.

- (a) Hydrogen Sulfide (Low-Level): Evaluate using EPA Method 15 and EPA Method 16 or use ASTM D-1945M (Thermal Conductivity Detector), ASTM D-5504 (sulfur chemiluminescence detector), and ASTM D-6228 (flame photometric detector) as alternate methods.
- (b) Oxygen, Nitrogen, Carbon Dioxide, Hydrogen Sulfide (High-Level), Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, Decanes+: Evaluate per ASTM D-1945, ASTM D-3588, and ASTM D-2597 (GC/TCD). Note: This analysis requires all three methods specified. The base method is ASTM D-1945, which is modified to extend the hydrocarbon analysis range based on information from the other two methods.
- (c) BTEX: Evaluate per EPA 8021 B (GC/FID) or use ASTM D-3170, GPA 2286, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.
- (d) API Gravity of crude or condensate at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer). Note: if water is entrained in sample, use ASTM D 287. If needed calculate Specific Gravity 60/60°F = $141.5 / (131.5 + \text{API Gravity at } 60^\circ\text{F})$
- (e) Specific Gravity of Produced Water at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer). If needed calculate API at 60°F = $(141.5 / \text{SG at } 60^\circ\text{F}) - 131.5$
- (f) Molecular Weight of gaseous phase by calculation per ASTM D-3588.
- (g) Water and Sediment in Crude Oil by Centrifuge Method per ASTM D-4007.

12.4 Laboratory Reports

Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. The laboratory results must be reported as specified in section 11 and shall include the data requirements listed in Table 1.

Table 1: Laboratory Data Requirements

WT% CO ₂ , CH ₄
WT% C ₃ -C ₉ , C ₁₀ +
WT% BTEX
WT% O ₂
WT% N ₂
WT% H ₂ S
Molecular Weight of gas sample (gram/gram-mole)
Liquid phase specific gravity of produced water (gram-cc)
Gas Oil or Gas Water Ratio (scf/barrel)
API gravity of crude oil or condensate at 60°F
Water Sediment and Volume (ASTM D-4007)
Post-Test Cylinder Water Volume
Post-Test Cylinder Oil Volume

13. ALTERNATIVE TEST PROCEDURES OR METHODS

Test procedures, other than specified above, shall only be used if prior written approval is obtained from the ARB Executive Officer. In order to secure the ARB Executive Officer's approval of an alternative test procedure or method, the applicant is responsible for demonstrating to the ARB Executive Officer's satisfaction that the alternative test procedure is equivalent to this test procedure.

- (1) Such approval shall be granted on a case-by-case basis only. Because of the evolving nature of technology and procedures and methods, such approval shall not be granted in subsequent cases without a new request for approval and a new demonstration of equivalency.
- (2) Documentation of any such approvals, demonstrations, and approvals shall be maintained in the ARB Executive Officer's files and shall be made available upon request.

13. REFERENCES

ASTM D-70	<i>Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)</i>
ASTM D-287	<i>Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)</i>
ASTM D-1945M	<i>Standard Test Method for Analysis of Natural Gas by Gas Chromatography</i>
ASTM D-2597	<i>Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i>
ASTM D-3710	<i>Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography</i>
ASTM D-3588	<i>Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels</i>
ASTM D-4007	<i>Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method</i>
ASTM D-4052	<i>Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter</i>
ASTM D-5002	<i>Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer</i>
ASTM D-5504	<i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence</i>
ASTM D-6228	<i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection</i>
EPA Method 15	<i>Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources</i>
EPA Method 16	<i>Semicontinuous Determination of Sulfur Emissions from Stationary Sources</i>
EPA Method 8021B	<i>Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors</i>

EPA Method 8260B	<i>Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)</i>
EPA Method TO-14	<i>Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography</i>
EPA Method TO-15	<i>Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)</i>
GPA 2174	<i>Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography</i>
GPA 2177	<i>Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i>
GPA 2261	<i>Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography</i>
GPA 2286	<i>Extended Gas Analysis Utilizing a Flame Ionization Detector</i>

FORM 1
Flash Analysis Sampling Field Data Form

Attach a sketch or diagram of all vessels in the separator and tank system including the location from where the sample was taken.

Date of Testing:	
Production Company Name:	
Address:	
City:	
Contact:	Phone:
Sampling Company Name:	
Address:	
City:	
Contact:	Phone:
Enter one unique identification name or number for the type of vessel sampled.	
Primary Pressurized Separator ID:	
Portable Separator ID:	
Separator Pressure:	psig
Separator Temperature:	°F
Crude Oil or Condensate Throughput:	Barrels/Day
Produced Water Throughput:	Barrels/Day
Gas Volume (if metered):	Mcf/Day
Percent Water Cut: %	Number of wells in system:
Crude Oil Storage Tank Temperature (if heated):	°F
Sample Cylinder ID Number:	
Cylinder Type:	Displacement Liquid:
Sampling Pressure:	Sampling Temperature:
Cylinder Volume:	Volume of Liquid Collected:

Appendix B

Calculation for Determining Vented Natural Gas Volume from Liquids Unloading of Natural Gas Wells

$$E_{scf} = \left(\frac{V * P_1 * T_2}{P_2 * T_1} \right) + (FR * HR)$$

Where:

E_{scf} is the natural gas emissions per event in scf

$V = \pi * r^2 * D$ (volume of the well)

$r = \frac{CD}{2}$ (radius of the well)

CD is the casing diameter in feet

D is the depth of the well in feet

P_1 is the shut-in pressure of the well in psia

P_2 is 14.7 psia (standard surface pressure)

T_1 is the temperature of the well at shut-in pressure in °F

T_2 is 60 °F (standard surface temperature)

FR is the metered flowrate of the well or the sales flowrate of the well in scf/hour

HR is the hours the well was left open to atmosphere during unloading

$$CH_4 \text{ emissions} = E_{scf} * MF_{CH_4} * MV * MW_{CH_4} * \left(\frac{\text{metric ton}}{2204.6 \text{ lb}} \right)$$

Where:

$CH_4 \text{ emissions}$ is in metric tons per event

$MF_{CH_4} = \frac{\text{lbmole } CH_4}{\text{lbmole gas}}$ (mole fraction of CH_4 in the natural gas)

$MV = \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}}$ (molar volume)

$MW_{CH_4} = \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4}$ (molecular weight of CH_4)

Appendix C

Record Keeping and Reporting Information

Table 1
Flash Analysis Test Results & Accompanying Information

Instructions

1. Complete one table for each separator and tank system.
2. Attach a copy of the laboratory reports and calculations when submitting.
3. Retain copies of all records at the operation for ARB or local air district inspection.
4. Submit results to ARB annually by e-mail at oil&gas@arb.ca.gov or send by mail to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814 Sacramento, California 95814

Date of Testing:	
Company Name:	
Address:	
City:	
Contact Person:	Phone Number:
Emissions Test Result: metric tons methane per year	
Annual Crude Oil or Natural Gas Throughput: Barrels / Mcf	
Annual Produced Water Throughput: Barrels	
Number of Wells Serving Primary and Secondary Vessel System:	
Number of Tanks in System:	Number of Separators in System:

Table 2
Reciprocating Natural Gas Compressors

Instructions

1. Complete one table for each natural gas compressor tested.
2. Retain a copy of this table at the operation for ARB or local air district inspection for each reciprocating natural gas compressor at the operation.

Company Name:	
Address:	
City:	
Contact Person:	Phone Number:
Compressor Manufacturer:	Rated Horsepower:
Rod Packing or Seal Emission Measurement: ppmv / scfh	
Date of Last Rod Packing or Seal Maintenance:	

Table 3
Liquids Unloading of Natural Gas Wells

Instructions

1. Complete one record for each natural gas well that is vented in order to remove accumulated liquids.
2. Retain copies at the operation for ARB or local air district inspection.
3. Submit results to ARB annually by e-mail at oil&gas@arb.ca.gov or send by mail to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814 Sacramento, California 95814

Company Name:	
Address:	
City:	
Contact Person:	Phone Number:
Well ID or Number:	Volume of Gas Vented: scf
Installed Liquid Removal Equipment:	

Table 4
Leak Detection and Repair Summary

Instructions

1. Complete one summary table annually.
2. Retain copies at the operation for ARB or local air district inspection.
3. Submit results to ARB annually by e-mail at oil&gas@arb.ca.gov or send by mail to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814 Sacramento, California 95814

Company Name:		
Address:		
City:		
Contact Person:		Phone Number:
Component Type	Number Inspected	Number Leaks Above Standard
Valve		
Fitting		
Flange		
Threaded-Connection		
Process Drain		
Stuffing Box		
Pressure Relief Valve		
Diaphragm		
Hatch		
Sight Glass		
Meter		
Pipe		
Liquid Seal System		
Other		

