

Petroleum and Natural Gas Systems Emissions Reporting Guidance for California's Mandatory GHG Reporting Program

Introduction

This document describes the requirements for facility operators of petroleum and natural gas systems for reporting greenhouse gas (GHG) emissions data under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 *et seq*) (MRR). The petroleum and natural gas systems sector consists of eight industry segments as defined in section 95150 of MRR.

Unlike MRR, this guidance does not have the force of law, does not establish new mandatory requirements for greenhouse gas (GHG) reporting, and in no way supplants, replaces, or amends any of the legal requirements of the Regulation. Conversely, an omission or truncation of regulatory requirements in this guidance does not relieve operators of their legal obligation to fully comply with all requirements of MRR.

The current version of this document incorporates reporting requirements for pneumatic devices (FAQ 3.14) and accuracy requirements for continuous bleed pneumatic devices (section 2.3) going into effect beginning with 2019 data. This version also retains an example scenario (Section 1.5, Example 4) that illustrates how regulatory changes that went into effect for 2018 data could affect a facility's calculated total and covered emissions.

This guidance does not discuss reporting requirements related to covered product data. For additional information about covered product data reporting for petroleum and natural gas systems, see the [Petroleum and Natural Gas Systems Covered Product Data Reporting and Verification Guidance](#) document.

1 Identifying and Defining Facility Industry Segments

Section 95101(e) of MRR describes eight industry segments for petroleum and natural gas systems. Of these segments, two industry segments—natural gas distribution, and onshore petroleum and natural gas production—have specific, more specialized “facility” definitions within MRR. Beginning with 2018 data reported in 2019, onshore natural gas processing plants will also have a unique “facility” definition per section 95102 in the MRR amendments adopted in 2017. Section 95102 of the 2016 MRR also includes a revised definition for onshore petroleum and natural gas production facility, to clarify the distinction between production facilities and gas plant facilities. These definitions appear below. The revised definitions, which apply to 2018 and subsequent years, are also described in the industry segment descriptions found in

section 95150 of the 2016 MRR. All other industry segments will continue to use the general definition of "facility" in section 95102(a) of MRR.

1.1 Natural Gas Distribution Facility Definition

Section 95102(a) of MRR includes a specialized facility definition for natural gas distribution facilities:

"'Facility,' with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, means the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system."

1.2 Onshore Natural Gas Processing Facility (2018 Data and Later)

Section 95102(a) of the 2016 MRR includes a new, specialized facility definition for onshore natural gas processing facilities that will be applicable to the 2018 data year and subsequent years. For reporting of 2017 data in 2018, facilities that meet the definition of onshore natural gas processing will continue to report according to the definitions in the 2014 MRR. The new definition applicable for 2018 data reporting and subsequent years is as follows:

"'Facility,' with respect to onshore natural gas processing for the purposes of sections 95150 to 95158 of this article, means equipment associated with the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, including separation of sulfur and carbon dioxide, that processes an annual average throughput of 25 MMscf per day or greater, or whose owner/operator does not also own/operate a production facility in the same basin."

1.3 Onshore Petroleum and Natural Gas Production Facility Definition

Section 95102(a) of MRR includes a specialized facility definition for onshore petroleum and natural gas production facilities as follows:

"'Facility,' with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred and CO₂ EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single basin as defined in section 95102(a). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production

facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

The following was added to the 2016 MRR to clarify the distinction between production facilities and gas processing plant facilities.

"Onshore natural gas processing equipment as defined in section 95150(a)(3) that is owned and/or operated by the facility owner/operator and located within the same basin, is considered "associated with a well pad" and is included with the onshore petroleum and natural gas production facility, unless such equipment is required to be reported as part of a separate onshore petroleum and natural gas processing facility."

1.3.1 Application of the Term "Associated with"

Onshore petroleum and natural gas system emissions sources are considered "associated with" the hydrocarbon stream produced from the well pad. This includes steam generators, dehydrators, amine treaters, and other equipment (portable and stationary) that are used in the production and treatment of the hydrocarbon stream produced at the well pad. The "associated with" term is also inclusive of cogeneration facilities that supply steam and/or electricity to the well pad.

1.3.2 California Geologic Provinces (Basins)

Onshore petroleum and natural gas production facilities in California are required (under section 95153) to aggregate and report applicable GHG emissions using the "basin" footprint, pursuant to the definition of "basin" in section 95102(a), as defined in the following publication:

AAPG-CSD Geologic Provinces Code Map, R.F. Meyer, L.G. Wallace, and F. J. Wagner, Jr., *The American Association of Petroleum Geologists Bulletin*, V. 75, No. 10 (October 1991), pgs., 1644 – 1651, 1991.

This journal article is copyright protected and cannot be freely distributed by the California Air Resources Board (CARB). Reporters may access the complete article free of charge at many California public libraries. To aid reporters in the determination of their reporting footprint and correct basin name and number, CARB staff have constructed Table 1, which lists each California county or counties included in each basin by name and number (as defined in the reference publication). Note that, in many cases, a basin may contain multiple California counties. Offshore basins do not necessarily correspond to individual onshore California counties.

Table 1: Basin IDs Defining Oil and Natural Gas Production Facility Reporting Footprint

| Basin Name | Basin Number | California County(ies) |
|--|---------------------|---|
| Onshore Basins | | |
| Southern Oregon | 620 | Lassen, Modoc |
| Great Basin | 625 | Inyo, Mono |
| Mojave | 640 | San Bernardino |
| Salton | 645 | Imperial, Riverside |
| Sierra | 650 | Alpine, Amador, Calaveras, El Dorado, Mariposa, Nevada, Placer, Plumas, Sierra, Tuolumne, Yuba |
| Klamath Mountain | 715 | Del Norte, Shasta, Siskiyou, Trinity |
| Eel River | 720 | Humboldt |
| Northern Coast Range | 725 | Alameda, Lake, Mendocino, Napa, Santa Clara, Sonoma |
| Sacramento | 730 | Butte, Colusa, Contra Costa, Glenn, Sacramento, San Joaquin, Solano, Sutter, Tehama, Yolo |
| Santa Cruz | 735 | Marin, Santa Clara, Santa Cruz, San Francisco, San Mateo |
| Coastal | 740 | Monterey, San Luis Obispo |
| San Joaquin | 745 | Fresno, Kern, Kings, Madera, Merced, San Benito, Stanislaus, Tulare |
| Santa Maria | 750 | Santa Barbara |
| Ventura | 755 | Ventura |
| Los Angeles | 760 | Los Angeles, Orange |
| Capistrano | 765 | San Diego |
| Offshore Basins | | |
| Eel River | 945 | Not applicable |
| Point Arena | 948 | |
| Santa Cruz (Bodega) | 950 | |
| Santa Maria | 953 | |
| Santa Barbara Channel | 955 | |
| Pacific Coast (Outer) | 956 | |
| Southern California borderlands | 957 | |

1.4 Definition of “Facility” for all Other Industry Segments

The general “facility” definition in section 95102(a) of MRR applies to the other industry segments listed in section 95101(e), including offshore petroleum and natural gas

production, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, import, and export facilities. The definition is as follows:

“‘Facility,’ unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.”

Natural gas distribution facilities and onshore petroleum and natural gas production facilities are subject to the more specific definitions in section 95102(a) (described in Sections 1.1 and 1.3 of this guidance document) instead of this general facility definition. Beginning with 2018 data reported in 2019, onshore natural gas processing facilities also are subject to a more specific definition in section 95102(a), which is quoted in Section 1.2 of this guidance document, instead of this general facility definition.

1.5 Examples for Applying Facility Definitions for Oil and Gas Facilities

These examples may be based in part on case-specific factual circumstances and are offered here only as guidance that does not supplant the requirements of MRR.

Example 1: An onshore petroleum production operator in a single hydrocarbon basin owns greater than a 50 percent share in a cogeneration plant, which supplies steam to some of the wells for production. How many CARB facility IDs does this owner need?

Answer: One. The cogeneration plant is associated with the onshore petroleum production facility and emissions from the cogeneration plant must be reported with the other emissions associated with the well pad within the geologic basin because the operator owns greater than a 50 percent share in the cogeneration plant as specified in the definition of “onshore petroleum and natural gas production facility” in section 95102(a).

Example 2: An oil company operates a natural gas processing plant that has a throughput of 35 MMscf/day. The oil company also owns and operates multiple production well pads in the same geologic basin. How many CARB facility IDs are needed?

Answer: At least two. The natural gas processing facility has a separate facility ID from the well pads.

Example 3: A liquefied natural gas storage facility is contiguous to a commonly owned cogeneration plant. How many CARB facility IDs do the facility and plant need?

Answer: One. The liquefied natural gas storage facility is contiguous to the cogeneration facility. Because MRR does not include a specific, specialized facility definition for liquefied natural gas storage facilities, the general facility definition in section 95102(a) of MRR applies, so this is considered a single facility.

Example 4: An onshore production facility operates natural gas processing equipment in the same hydrocarbon basin. Which emissions must be reported to CARB?

Answer: Beginning with 2018 data, section 95101(b)(3) requires facility operators to include specified supplier emissions when determining applicability relative to the thresholds for emissions reporting. Supplier emissions from natural gas that is delivered to a customer must be reported in Subpart NN with a supplier type of "Intrastate natural gas pipelines." Those supplier emissions are not considered "covered emissions" if the natural gas is delivered to a covered entity subject to the Cap-and-Trade Regulation. Covered emissions from supplied natural gas reported in Subpart NN are calculated by CARB outside of Cal e-GGRT, and therefore are not reflected in the covered emissions displayed in Cal e-GGRT.

Also beginning with 2018 data, the definition of onshore natural gas production facility now considers natural gas processing equipment to be associated with a well pad. Therefore, the emissions from natural gas processing facilities are required to be included when determining applicability relative to the thresholds for emissions reporting.

More information about applicability determination is included in section 1 of [Reporting Guidance for Determining Rule Applicability](#).

1.6 Reporting by Sub-facility

MRR specifies that emissions and product data must be disaggregated within the basin reporting footprint to the sub-facility level when reported via the California Electronic Greenhouse Gas Reporting Tool (Cal e-GGRT). Sub-facility is defined in terms of single townships or a group of contiguous or adjacent townships, as identified in the Public Land Survey System of the United States. Sub-facilities may be further disaggregated according to similar operational, geological, or geographical characteristics. Reporters should refer to the definition of sub-facility found in section 95102(a) of MRR for additional information. Entities that have already been reporting emissions and product data at the sub-facility level should continue reporting with the same subdivision of information; however, the facility's GHG Monitoring Plan must provide a map or a list identifying the townships, ranges, and section numbers that comprise the geographic boundaries of the sub-facilities. Production data must be further disaggregated between thermal and other-than-thermal (i.e., non-thermal) production processes at the sub-facility level.

2 New and Modified Requirements for 2018 Data Reported in 2019, and for Subsequent Years

This section discusses new requirements that became effective January 1, 2018. Facility operators should be aware of these modifications for the purpose of implementing compliant data acquisition methods during 2018 and subsequent years.

2.1 Requirements for Using the Flash Liberation Test to Quantify Emissions

For the 2018 data year and subsequent years, the revised Flash Liberation Test procedure found in Appendix B of the 2016 MRR must be used, if the flash procedure is used to quantify emissions (section 95153). Additionally, beginning with the 2018 data year, the Flash Liberation Test(s) must be performed at least annually, as applicable. Section 95153(v)(1)(A) now explicitly requires the test to be representative.

2.2 Requirements to Report Sorbent Emissions

Onshore petroleum and natural gas production and natural gas distribution facilities must report CO₂ emissions from the reaction of acid gas and sorbent for all combustion units that are fluidized bed boilers, equipped with a wet flue gas desulfurization system, or use other acid gas emission controls with sorbent injection (section 95153(y) of MRR). Reporters must use the methods found in United States Environmental Protection Agency (U.S. EPA) Mandatory GHG Reporting Rule (section 40 CFR § 98.33(d)) to calculate sorbent related emissions unless the CO₂ emissions are monitored by CEMS (section 95153(y)(5)).

2.3 Meter Accuracy Requirements for Continuous Bleed Pneumatic Devices

By January 1, 2019, all continuous bleed pneumatic devices must meet the accuracy requirements of section 95103(k) in the manner specified in section 95153(a).

3 Frequently Asked Questions

This section provides answers to frequently asked questions from facility operators of petroleum and natural gas systems. These answers may be based in part on case-specific factual circumstances and are offered here only as guidance that does not supplant the requirements of MRR.

3.1 If an operator does not have a certain source at its facility, can the fields in Cal e-GGRT be left blank for those sources?

No. Operators of all petroleum and natural gas facilities should report zero (0) in Cal e-GGRT where individual source emissions can be demonstrated to be zero (i.e.,

no emissions occurred from the source in question for the entire reporting period). This will allow CARB and the verifier to know that the operator did not have emissions associated with the specific sources instead of failing to insert data for those sources. The operator must demonstrate to the satisfaction of the verifier that no emissions occurred. Additionally, in cases where the emissions are less than one-thousandth of a ton, the user should enter '0' into Cal e-GGRT. As mentioned above, the user should retain the records of the actual emissions for verification purposes.

3.2 Do operators have to report emissions from the blowdown of very small volumes?

Section 95153(g) of MRR requires all facility operators, except operators of offshore petroleum and natural gas production facilities, to report emissions resulting from the depressurization of equipment and pipelines caused by human intervention or taking equipment out of service for maintenance (excluding depressurizing to a flare, overpressure relief, operating pressure control and venting and blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading).

Section 95153(g)(1) of MRR exempts reporting blowdown emissions from physical volumes less than 50 cubic feet (cf).

Reporters must calculate the unique physical volume for each blowdown incident. Pursuant to section 95153(g)(1) this volume shall be determined by engineering estimates based on best available data. Actual measurements of variables such as tubing diameter and pipe length would also be acceptable.

In addition to physical blowdown volume, the following variables must also be determined:

N = number of occurrences of blowdowns for each unique physical volume in the calendar year. Reporters should maintain a list and record the number of blowdowns per calendar year.

T_a = Temperature at actual conditions. Reporters should be able to determine this variable from any number of sources: e.g., System Control and Data Acquisition (SCADA) systems, thermometer.

P_a = Absolute pressure at actual conditions in the unique physical volume. Reporters should be able to determine this value from a SCADA system or via an engineering estimate based on system standard operating parameters when actual pressure measurements are not available.

Reporters should always use the most accurate data available when deriving the variables required as inputs to this emissions calculation methodology. The verifier must review the data sources during verification to ensure that the input data meet accuracy requirements.

3.3 How do operators report emissions in cases where the compressor was in the non-operating and depressurized mode during the reporting period and no measurement of emissions in the non-operating mode has been taken in the last three calendar years?

The monitoring requirements for compressors with a rated horsepower of 250 or greater in the “not operating, depressurized mode” are detailed in sections 95153(m)(1)(C) and 95153(n)(1)(C) of MRR. If no measurement data has yet been acquired within the three year monitoring period, the operator must measure emissions as specified in section 95153(m) or (n), unless one of the following scenarios applies. If the compressor is operated for two hundred hours or less per calendar year and an applicable meter is not present on the compressor, an engineering estimate can be used to determine the MT_m variable.” In addition, compressor emissions reported as de minimis can be estimated using alternative methods of the operator’s choosing, pursuant to section 95103(i).

3.4 What if sampling required under MRR exposes facility personnel to hazardous concentrations of H₂S in compressor emissions? Are operators still required to conduct sampling under these circumstances?

Activities undertaken to collect and acquire data reported under MRR should never be conducted in a manner that puts personnel safety at risk. Reporters should refer to sections 95154(a)(3) and (4) of MRR (Monitoring and QA/QC Requirements) where personnel are directed to use either an infrared laser or an optical gas imaging instrument “for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.”

Sections 95153(m) and 95153(n) of MRR describe emissions measurement and quantification methodologies for centrifugal and reciprocating compressors, respectively. These two sections specify the methods used to quantify vent emissions, which include calibrated bagging, high volume sampler, or a permanent or temporary meter.

3.5 How do operators apportion fugitive emissions measurements over the five-year period mentioned in section 95153(o)(8)(A) of MRR?

U.S. EPA has issued guidance concerning this issue and this guidance is reproduced below. Operators are directed to follow this guidance in quantifying and reporting emissions covered in section 95153(o) of MRR.

Reporter inquiry to U.S. EPA:

“Q651. Under Section 98.233(q)(8)(i), a company may elect to conduct leak detection on a multiple year cycle, up to a maximum of five years, with the number of stations monitored ‘approximately equal across all years in the cycle.’ The preamble to the final rule says ‘a minimum of 20%’ per year (76 FR 80569).

Would a monitoring plan that results in 10% of stations being monitored in each of the first two years, followed by 40% of stations in year 3, 20% in year 4 and 20% in year five, be consistent with the rule language of 'approximately equal across all years in the cycle.'"

U.S. EPA response:

"A651. Yes. According to 98.233(q)(8)(i), 'Natural gas distribution facilities may choose to conduct leak detection at T-D transfer stations over multiple years, not exceeding a five-year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option, then the number of T-D transfer stations monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.' EPA confirms that an approach of conducting monitoring at 10% of the facilities in each of the first two years, followed by 40%, 20% and 20% in years three, four and five would be consistent with the rule language that the number of stations monitored be 'approximately equal' over the number of years surveyed."

This text can be found at the following web-link:

<http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=118587545>.

3.6 In what cases should an operator use the "common pipe" method for reporting combustion emissions?

A "common pipe" method, as described in section 95115 of MRR, is still applicable for most fuels as described in section 95153(y)(1)(A). For combustion units that combust field gas, process vent gas, non-pipeline quality natural gas or a blend of field and process vent gas, the "common pipe" method also applies. Section 95153(y)(2)(A) indicates that company records may be used to determine the volume of fuel combusted, and for purposes of the fuels listed in section 95153(y)(2), company records may include records related to the common pipe that transfers fuel to particular units. For reporting emissions from units downstream of the common pipe, please follow the [Guidance for Aggregation of Emitting Units](#) document.

3.7 What are the verification requirements for activity data reported pursuant to section 95157?

Facility operators for every industry segment are required to report activity data contained in section 95157 of MRR. Activity data reported under section 95157 must be verified for conformance by a third-party verification body pursuant to section 95131(b)(10). The activity data reported pursuant to section 95157 are not part of a facility's covered emissions, and as such, are not subject to material misstatement assessment.

3.8 When determining whether a natural gas source is “pipeline quality natural gas,” is it acceptable for the operator to make the determination based on the annual weighted averages of monthly measurements for CH₄, CO₂, and HHV?

Yes, that would be considered an acceptable method for determining pipeline quality criteria. If the annual weighted averages of monthly measurements for CH₄, CO₂, and HHV meet the “pipeline quality natural gas” criteria for those parameters (i.e., at least 90% CH₄ by volume, less than 5 percent CO₂ by volume, and HHV greater than 970 and less than or equal to 1,100 btu/scf), the gas would be considered “pipeline quality” for the entire data year.

3.9 Since the CO₂ emissions method in section 95153(y)(2) of MRR is based on carbon content (similar to a “Tier 3” method) and not based on a default emission factor, is it acceptable to use section 95153(y)(2) for a natural gas source that does meet the definition of “pipeline quality” natural gas?

Yes, the operator may choose to use the method in section 95153(y)(2) to quantify combustion emissions for natural gas that does meet the “pipeline quality” definition.

3.10 If an operator follows the method in section 95153(y)(1) of MRR, because the fuel is a standard fuel or is pipeline quality natural gas, and selects an applicable Tier method from section 95115, does the operator need to follow all of the quality assurance and reporting requirements described in section 95115?

If a Tier method from section 95115 is selected to quantify combustion emissions based on the application of section 95153(y)(1), the reporter *must* follow all of the Tier selection, monitoring, sampling frequency, and other quality assurance requirements in section 95115 that are associated with accurately quantifying emissions. For facilities in the oil and gas sector, the additional reporting requirements of section 95115 that are prompted when reporting the combustion data in subpart C of Cal e-GGRT (e.g., reporting fuel use by device type for a common pipe source) are not required when using the 95153(y)(1)(A) method.

3.11 Do vented emissions from “rotary vane” compressors need to be reported?

Vented emissions from “rotary vane” compressors, and any other compressors that operate on the principle of a rotating shaft, should be reported as emissions from centrifugal compressors.

3.12 If the vented emissions from compressors are reported as *de minimis*, is it acceptable to modify or omit the vent testing requirements described in sections 95153(m) and (n) of MRR?

If the vented emissions from compressors meet the *de minimis* thresholds, and the chosen method for quantifying vented emissions is reasonable, the vent testing requirements described in sections 95153(m) and (n) may be modified or omitted. Verifiers must ensure that the methods used by the operator to quantify emissions reported as *de minimis* are reasonable, unlikely to be biased high or low, and that the actual emissions are unlikely to exceed the *de minimis* threshold.

3.13 How should compressor venting emissions be reported if the compressors are completely self-contained and have no vents or vent stacks, or if the vented emissions from vents are captured to a vapor recovery system?

If compressors have no vents or vent stacks, or if 100 percent of the vented emissions are routed to a vapor recovery system, the operator should quantify and report the vented emissions from such compressors as zero (0). Such compressors would still be subject to the reporting requirements for leaks and for fuel combustion, as described in Subarticle 5 of MRR.

3.14 How should emissions from natural gas-powered intermittent-bleed pneumatic devices be quantified and reported, if the operator has documentation demonstrating that the actual bleed rate for the devices is less than six scf per hour?

Emissions from natural gas-powered intermittent-bleed pneumatic devices are quantified using Equation 2 in section 95153(b) of MRR and the "intermittent bleed" emission factor of 13.5 scf/hour/component listed in Table 1A of Appendix A of MRR. If the operator has documentation that demonstrates that the devices bleed at a rate of less than six scf/hour/component, such as original equipment manufacturer's specifications, or measurement data, the operator must still quantify the emissions using the 13.5 scf/hour/component emission factor.

Emissions from pneumatic devices are reported in Subpart W of Cal e-GGRT using the Subpart W, "Petroleum and Natural Gas Systems – Emissions Reporting Workbook." The workbook contains a separate tab for each industry segment. The following industry segments are required to report emissions from pneumatic devices in this workbook: onshore petroleum and natural gas production, underground natural gas storage, and onshore natural gas transmission compression. Within the industry segment tab, pneumatic device emissions are reported under one of six device categorizations: metered continuous high bleed; metered continuous low bleed; non-metered continuous

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high bleed; non-metered continuous low bleed; intermittent (<6 scf/hr); and intermittent (≥6 scf/hr).

In this example, the pneumatic devices are intermittent-bleed and the actual bleed rate is less than six scf/hr, so the operator must report emissions under the heading “Natural gas intermittent (<6 scf/hr) pneumatic device venting” in the appropriate tab of the Subpart W, Petroleum and Natural Gas Systems – Emissions Reporting workbook.

Table 2 below summarizes MRR and Cap-and-Trade regulatory language regarding pneumatic devices to help operators determine whether emissions from a particular type of pneumatic device have a compliance obligation for a given reporting year and industry segment. As indicated in Table 2, emissions from pneumatic devices that fall under the category of “Intermittent (<6 scf/hr)” are not covered for all applicable source categories in all reporting years. Thus, in this example, the reported emissions would not have a compliance obligation.

Verifiers must evaluate pneumatic device emissions as a part of their risk analysis during verification, including the determination of whether pneumatic devices are continuous-bleed or intermittent-bleed devices. Verifiers should identify emissions from intermittent bleed devices that are reported in the “Intermittent (<6 scf/hr)” category in Cal e-GGRT as high risk because these emissions are exempt from a compliance obligation. Verifiers should review evidence that the actual bleed rate is less than six scf/hour and that the device is not a continuous bleed device.

Table 2: Pneumatic Device Covered Emissions Status, 2014 – 2019+

| Applicable Industry Segment | Data Year | Emissions Covered? | | | |
|---|-------------------------|-----------------------------------|--------------------------|--------------------------|------------------------------------|
| | | Continuous Low Bleed ¹ | Intermittent (<6 scf/hr) | Intermittent (≥6 scf/hr) | Continuous High Bleed ² |
| Onshore petroleum and natural gas production, Underground natural gas storage | 2014 | No | No | No | No |
| | 2015 | | | <u>Yes</u> | <u>Yes</u> |
| | 2016 | | | | |
| | 2017 | | | | |
| | 2018 | | | | |
| 2019+ | <u>Yes</u> ³ | No ⁴ | | | |
| Onshore natural gas transmission compression facility operated by LDC | 2014+ | No ⁵ | | | |

1. Low-bleed pneumatic devices bleed at a rate ≤ 6 scf/hour (MRR, section 95102)
2. High-bleed pneumatic devices bleed at a rate > 6 scf/hour (MRR, section 95102)
3. Beginning with reporting year 2019, emissions from low bleed pneumatic devices are no longer exempt from a compliance obligation, unless they bleed intermittently (see next note) (C&T Regulation, 95852.2(b)(6))
4. Beginning with reporting year 2019, intermittent-bleed devices that are not considered high bleed (i.e., intermittent-bleed devices with bleed rate < 6 scf) are exempt from a compliance obligation (C&T Regulation, 95852.2(b)(7) & 95802 – ‘definition of intermittent bleed pneumatic devices’)
5. All vented and fugitive emissions reported for onshore natural gas transmission compression (MRR 95152(e)) and natural gas distribution (95152(i)) by LDCs that report under section 95122 of MRR are exempt from a compliance obligation (C&T Regulation, 95852.2(b)(3))

3.15 What value should an operator use for the “Fraction of gas combusted” (η or “eta”), when using Equations 35 and 36 of section 95153 to quantify combustion emissions for “external” combustion devices, such as heaters or boilers?

The operator must use the default value of 0.995 for the term “ η ” in Equations 35 and 36 of section 95153 for all combustion unit types, including both “internal” and “external” combustion devices, unless the operator can provide objective evidence to the verification team to substantiate the use of a value other than the default factor of 0.995 (section 95153(y)(2)(C), Eq. 36). An example of such evidence could include a gas composition analysis of a combustion unit’s exhaust that demonstrates the validity of an alternative engineering estimate.

3.16 Are “sulfatreat” systems, and other types of systems that use a solid medium to remove sulfur gases, subject to emissions reporting under the “acid gas removal vent” source category?

No. The emissions quantification methods required pursuant to the “acid gas removal vent” source category (see section 95153(c)) are intended to quantify CO₂ emissions from systems that routinely remove CO₂ from the fuel gas stream, and then vent this CO₂ directly to the atmosphere upon regeneration of the system media (e.g., an amine solvent). Systems that use an iron oxide or other solid medium to remove sulfur gases from an enclosed stream of natural or associated gas, and that do not routinely vent CO₂ to the atmosphere, are not subject to emissions reporting under the acid gas removal vent source category in section 95153(c) because the media from these systems do not remove CO₂ from the fuel stream. However, the vessels of such systems would be subject to blowdown emissions reporting, as applicable, according to section 95153(g).

3.17 Do combustion emissions from small compressors (less than 130 horsepower) need to be reported? If so, how should those emissions be quantified if the compressor engine is powered by the gas it is compressing, and there is no fuel meter?

Yes. Combustion emissions from all compressors operated by an internal combustion engine, regardless of the rated heat capacity, must be reported as covered emissions, using the appropriate quantification method. If the fuel for such devices is not metered, the operator may quantify the fuel usage using the number of operating hours for the devices, and the demonstrated hourly fuel use rate, per the device manufacturer's specifications. However, the hours of operation and the hourly fuel use rate data (e.g., the "load" rate for the device under actual operating conditions) must meet the measurement accuracy requirements of section 95103(k). If the accuracy of the number of operating hours and/or the actual hourly fuel use rate cannot be demonstrated to the verifier, the operator may report the emissions in the de minimis category, if the requirements for de minimis reporting are met. If the operator cannot or does not wish to report the emissions in the de minimis category, the operator must use the missing data provisions to quantify the fuel use. The operator must use the maximum hourly fuel use rate for the device from the manufacturer's specifications to quantify missing fuel use rate data. If the hours of operation data are also missing, the operator must use the maximum number of hours during the data year for which the device may have been operating.

Pursuant to section 95153(y)(3), emissions from external fuel combustion sources (e.g., heaters and boilers) with a rated heat capacity of less than or equal to five MMBtu/hour do not need to be reported. Likewise, pursuant to 95153(y)(4), emissions from internal combustion sources, except compressor drivers, with a rated heat capacity equal to or less than one MMBtu/hour (or 130 horsepower) do not need to be reported.

3.18 How are de minimis emissions reported for oil and gas facilities in Cal e-GGRT?

To simplify reporting and ensure accurate categorization of de minimis emissions, operators must report Subarticle 5 (Subpart W) de minimis emissions in the Petroleum and Natural Gas Systems – Emissions Reporting Workbook. Operators may aggregate petroleum and natural gas systems de minimis emissions on one line of the workbook, or may choose to disaggregate the de minimis emissions by sub-facility. Operators must still disaggregate emissions that are not categorized as de minimis by sub-facility. See Figure 1 below for an example of a reporting configuration in Cal e-GGRT.

Figure 1: Example input for the Cal e-GGRT Subarticle 5 workbook “Onshore Petroleum and Natural Gas Production” section.

| Does Entire Row Contain Standard or De Minimis Emissions? (any de minimis emissions must be reported in separate row(s)). | Contiguous Property/Sub-Facility Name: | Metered natural gas high bleed pneumatic device and pneumatic pump venting | | |
|--|--|--|---|-------------------------|
| | | CO ₂ Emissions (tCO ₂) | CH ₄ Emissions (tCH ₄) | Total CO ₂ e |
| | Total - Standard Emissions | 805.0 | 7.0 | 952.0 |
| | Total - De Minimis Emissions | 125.0 | 2.6 | 179.6 |
| Standard | Watson Shale 25 | 250.0 | 5.0 | 355.0 |
| De Minimis | Watson Shale 25 - De Minimis | 2.0 | 0.3 | 8.3 |
| Standard | East Hill 23X | 555.0 | 2.0 | 597.0 |
| De Minimis | De Minimis Aggregation | 123.0 | 2.3 | 171.3 |

4 Additional Information

Detailed training materials for reporting using Cal e-GGRT: <https://ww2.arb.ca.gov/mrr-tool>.

The GHG Mandatory Reporting Regulation, with full requirements: <https://ww2.arb.ca.gov/mrr-regulation>.

Additional reporting and applicability guidance documents to assist reporters in complying with the MRR: <https://ww2.arb.ca.gov/mrr-guidance>.

Petroleum and Natural Gas Systems Covered Product Data Reporting and Verification Guidance: <https://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/oil-and-gas-product.pdf>

Contact the MRR helpdesk: ghgreport@arb.ca.gov.

For help with reporting or verification, please contact the appropriate staff member: <https://ww2.arb.ca.gov/mrr-contacts>.