California Air Resources Board

Frequently Asked Questions Regarding the GHG Mandatory Reporting Program

October 2009

This document has been revised. Please see:
http://www.arb.ca.gov/cc/reporting/ghg-rep/updated_faq.pdf

ARB's mandatory greenhouse gas (GHG) reporting regulation, which appears at sections 95100-95133 of title 17, California Code of Regulations, is a set of rules that establishes who must report GHG emissions to ARB and sets forth the requirements for measuring, calculating, reporting and verifying those emissions. ARB staff has prepared this document to address questions raised by facilities and entities in their first year of reporting. It will be updated periodically as other questions are considered.

If you have questions regarding any of the answers provided in this document, please contact ARB staff using the email ghgreport@arb.ca.gov.

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Unlike the regulation itself, this guidance does not have the force of law*. It is not intended to and cannot establish new mandatory requirements beyond those that are already in the regulation, and it does not supplant, replace or amend any of the legal requirements of the regulation. Conversely, this guidance's omission or truncation of regulatory requirements does not relieve operators of their legal obligation to fully comply with all requirements of the regulation.*

General Questions

Deadlines and Reporting Responsibilities

1. Q: **How do I determine if I am subject** to ARB's GHG emissions reporting regulation? **How do I report my emissions**?

   A: For most industrial sectors, the mandatory reporting regulation (http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf) specifies a reporting threshold of 25,000 metric tonnes of carbon dioxide (CO_2). Table 2.4c of ARB's *Instructional Guidance* document (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/00_06_GenProvs.pdf) provides equivalent reporting thresholds by fuel type. For example, if your facility uses more than 471,520 MMBtu (460,000,000 scf) of natural gas, or 12,000 short tons of coal, your facility is likely to be subject to the reporting regulation. Similarly, if your facility has the capacity to generate more than 1 MW of electricity and emits at least 2,500 metric tonnes of CO_2 from generating activities, you are required to report. Electricity retail providers and marketers are also required to report.

   If you believe you are subject to the reporting regulation, please contact ARB staff (ghgreport@arb.ca.gov) to receive information about how to report your emissions and to have an account created within the GHG Reporting Tool (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-tool.htm).

2. Q: **When** do I have to report **year 2008 emissions**? What is the **report year**?

   A: By June 1, 2009. In 2010 and later years, reports are due by April 1 or June 1, depending on your industry sector. Reporting deadlines are described on page 26 of the regulation http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf. The report year is the year for which emissions are being reported, not the year in which they are reported.

3. Q: My facility ceased operation mid-year. Am I required to report emissions from that calendar year? If the company was **sold mid-year**, who is responsible for reporting?

   A: Yes. Any facility that meets the applicability requirements is required to report, whether or not the facility or entity is operational when the reports are due. If the facility is not one of the identified sectors subject to reporting or is below the reporting thresholds, then reporting is not required. For those facilities or entities subject to reporting, responsibility for reporting annual emissions that occurred rests with the operator of the facility (both the former and the current operator). Ideally the current operator would receive all of the relevant information from the previous operator and report all emissions that occurred during that calendar year. Even if the plant is shut down, if reporting applicability is triggered, this does not relieve the operator(s) from reporting facility emissions that occurred during that report year. Please contact ARB staff to clarify facility-specific compliance requirements.

4. Q: For 2008, our facility emissions were **below the reporting threshold** due to business conditions. What do I need to do?

   A: If you have not been contacted by ARB and are not subject to reporting, you do not need to take further action. If you have been contacted by ARB and you do not think you are subject to reporting for 2008, please indicate in writing to ARB why you believe you are not subject to reporting. Be specific about your actual fuel use and whether you generated electricity in the report year. ARB staff will contact you with follow-up questions and may seek additional data under section 95101(d) of the regulation.

5. Q: Do marketers who operate generating facilities inside California need to **report data** on their facilities **in April** and data on their power transactions in June?

   A: No. ARB expects marketers with generating facilities to report all of their data by June 1, which is the same as for other power entities.

6. Q: I have a **cogeneration** system on-site. **When am I required to report** to ARB?

   A: When on-site and under the operational control of a facility subject to GHG reporting, the cogeneration report is included as part of the larger facility report and submitted on the same schedule. For 2008 emissions reports, all facilities report by June 1st. For 2009 and later emissions reports, the regulation requires reporting by April 1 if you operate a stand-alone cogeneration facility (i.e., cogeneration is the primary business) or maintain a cogeneration system that is under the operational control of a GSC facility, excluding an oil and gas production facility. For cogeneration systems under the operational control of a retail electricity provider, cement plant operator, refinery operator, hydrogen plant operator, or an oil and gas production facility, the reporting deadline is June 1, to match the reporting deadline for the whole facility. For more information, please see Table 3.2, page 3-4 of the *Instructional Guidance* (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/ghg-rep-guid.htm).

7. Q: For reporting **subsidiaries** as specified in 95104(a)(8), do office and other administrative buildings need to be reported?

   A: No. Only facilities with industrial combustion need to be included. Combustion for office related space heating or water heating is not considered industrial combustion.

Reporting Thresholds and Boundaries

8. Q: Would you please explain "**best available**" and "**pre-calculated**" emission calculations?

   A: As applied in the Reporting Tool, “best available” refers to an alternative method for emissions calculation used for 2008 emissions because a specific method prescribed in the regulation could not be used due to insufficient data. Data reported as best available should still be as accurate as is feasible. In later years emissions calculations must follow the methods specified in the regulation, so “best available” will not be an option.

   “Pre-calculated” emissions means emissions calculated outside the Reporting Tool using fuel sampling or other methods that are different than the use of default values available for direct calculation in the Reporting Tool.

9. Q: Are **emergency fire pumps** required to be included in the emissions report? If so, do the fuel flows to these units need to be measured by a meter demonstrated to be accurate to within +/-5 percent.

   A: Yes. Fire pumps are not exempt from reporting if the facility is subject to reporting. These emissions can probably be reported as *de minimis*, which means the fuel does not have to be measured within +/-5 percent accuracy if they are flagged as *de minimis* emissions.

10. Q: Are two **co-located facilities** (like a cotton gin and a vegetable oil refining company) **required to report separately**, or do they submit a single report?

    A: If the adjacent facilities are on contiguous property and are under common operational control as defined in the regulation, they must report as a single facility. If the two operations are under separate operational control, then they are required to report as two separate facilities. Or, if both are under common operational control, but the facilities are not on continuous and adjacent lands, the operations must also report as two separate facilities. Please contact ARB staff (ghgreport@arb.ca.gov) if you would like to discuss your specific situation.

11. Q: Is an **off-shore platform** connected to an on-shore facility the same facility, or should they report separately?

    A: They should report separately, even though they may be connected via pipeline or electricity transmission line. Facilities that are separated by a roadway may be grouped as a single facility if they are under common operational control. Facilities that are not located on contiguous property should report separately.

12. Q: Does fuel used for **non-production** activities (like gas used for a water heater for employee showers) need to be reported?

A: In most cases all stationary combustion sources at the facility should be reported. An exception is the case of a facility reporting electricity generation or cogeneration emissions only, whose primary business is in another sector and whose total emissions are less than 25,000 MT CO_2. For example, a university whose total emissions are under 25,000 MT may report emissions from its 1 MW cogeneration unit only.

13. Q: Is it necessary to report the **percentage of carbon** that is actually released as CO_2, versus reporting the total carbon content?

A: No. The regulation does not require or give reporters the option to account for un-combusted carbon (i.e., incorporated in fly-ash, bottom ash or anywhere else). The equations in the regulation assume complete combustion and release of all fuel carbon as CO_2.

14. Q: What are the reporting requirements for **hydroelectric plant operators**?

A: If you are the operator of a hydroelectric facility and are not a retail provider nor an importer/exporter of power, then you are not required to report. You should, however, examine the list of generating facilities posted on our website to ensure that your facility is listed and appropriately assigned an ARB identification number. This number will be used by power entities to report specified purchases from your facility.

If you are a retail provider and operate a hydroelectric facility, you are required to report certain non-emissions data for your facility. Please review Table 8.8 of ARB's *Instructional Guidance*.

15. Q: I operate a cogeneration system, but I **don't own the property** or the cogeneration equipment. I am surrounded by a refinery that is already subject to the reporting regulation. Who reports emissions from the cogeneration?

A: The entity with operational control is required to report, regardless of ownership. If two or more parties share operation of the cogeneration, the entity with the local air district permit is responsible for reporting.

16. Q: How do I report emissions from a company with a **large campus** with 40 buildings, including distinct groups of buildings spread out over a number of roads in the general area? There is no **physical boundary** as such around the whole campus. The campus as a whole emits >25,000 MT CO_2 from on-site combustion (primarily natural gas) annually but no individual building or boiler emits this amount. However, there is a central group of buildings that do emit over 25,000 MT CO_2.

A: The company should report as a single facility when emitting activities are located on contiguous or adjacent properties, or separated only by a public right-of-way.

Portions of the campus that are geographically independent (i.e., separated by more than just a public right-of-way) may be excluded from the report, or included as optional emissions.

17. Q: I have an electricity generation unit that uses **steam provided by natural gas fired boilers** to generate electricity. Will the electricity generation system be included in the reporting?

A: If natural gas is burned to generate steam, and then the steam is used to generate power, the unit is subject to reporting if the generating capacity is 1 MW or more and its CO_2 emissions are at least 2,500 MT for the report year. In this scenario, the boilers are included in the definition of "generating unit." Section 95102 states that "'generating unit' means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power."

18. Q: Are **diesel** fueled **vehicles** subject to this regulation?

A: Mobile sources (including cars and trucks) are not required to be reported. Facilities or entities with stationary combustion sources subject to reporting may include mobile sources, but this is optional.

19. Q: How do I report diesel engines and engines owned by my facility? Am I required to estimate and report how much fuel is used in all facility **vehicles**?

A: For facilities subject to reporting, emissions from stationary diesel engines must be reported, except for permitted emergency or backup engines. Emission factors for diesel fuel (distillate fuel oil #1, 2, & 4)) are provided in Appendix A of the regulation. Estimation of fuel use and emissions by vehicles is not required. If you voluntarily report emissions from mobile sources, you must identify those sources as "optional" in the Reporting Tool.

20. Q: Does an electricity generation facility that combusts **biogas** count **pass-through CO_2** emissions when determining if it meets the 2,500 MT CO_2 threshold?

A: No. For both generating units and general stationary combustion (GSC) sources, pass-through CO_2 associated with combusting biogas is not included when determining whether facilities meet reporting thresholds. Electricity generating and cogeneration facility CO_2 emissions from combusting fossil fuels and biomass-derived fuels (excluding pass-through CO_2 associated with combusting biogas) are included in the threshold determination, along with process emissions, and fugitive CO_2 emissions from geothermal facilities.

However, when *reporting* the emissions from combusting biogas, pass-through CO_2 is included and is in the emission factor provided in the regulation. Both emissions from combusting biogas as well as the pass-through CO_2 are reported as biomass-derived CO_2 in order to distinguish these emissions from those associated with fossil fuels.

For distribution of emissions for a cogeneration system, only CO_2 emissions from combusting fossil fuels are distributed between thermal energy and electricity generation.

21. Q: Is all **portable equipment**, such as flood pumps, exempt from reporting?

A: Yes, all portable equipment is exempt.

22. Q: If a facility such as a manufacturer or a wastewater treatment plant that emits less than 25,000 MT CO_2 installs a **cogeneration** system that emits >2,500 MT CO_2, is the **entire facility subject to reporting**, or is just the cogeneration subject to reporting?

A: If the facility total emissions are under 25,000 MT CO_2, the operator would only report emissions for the cogeneration unit. If the facility plus the cogeneration emissions exceed 25,000 MT CO_2, then reporting of overall facility emissions, including the cogeneration system, is required.

23. Q: Are **emergency** (black start) **generators** at an electricity generation facility exempt from reporting?

A: Yes, emergency generators that help restore station service power in the event of loss of grid electricity, and which are permitted as such by a local air district, are exempt from GHG emissions reporting. See section 95101(c)(3) of the regulation.

24. Q: Does a **university** qualify as a "school," thus making it exempt from Mandatory Reporting?

A: No, the regulation only exempts primary and secondary schools. Colleges and universities are not exempt from reporting. See section 95101(c) of the regulation. If the university as a "facility" emits more than 25,000 MT of CO_2 from stationary combustion, or has power generation or cogeneration $\geq$1 MW which emits more than 2,500 MT of CO_2, the university would be subject to GHG emissions reporting.

25. Q: We operate two **standby boilers** that operate less than 30 days per year. Are they considered **standby equipment** and exempt from reporting? They are not permitted as "standby" by the local air district, but cannot operate at the same time as a permitted cogeneration unit.

A: These boilers would not be exempt. All combustion sources specified in the regulation must be included in your emissions report unless they are identified by the local district as emergency or backup generators.

26. Q: Do I need to report fuel consumption for **exempt equipment** or exempt generating units?

A: No, but if you voluntarily report emissions from exempt sources, you must report the emissions as "optional" in the Reporting Tool.

27. Q: For a general stationary combustion (GSC) facility (i.e., not a refinery) that has wastewater treatment and a sulfur recovery unit (SRU), the regulation does not require reporting of the non-combustion (i.e., fugitive and process) water treatment or SRU emissions. Does the facility **have the option to report emissions** from **fugitive and process** emission sources, or is the report limited to emissions from stationary combustion sources?

A: If the facility is not a refinery but triggers the 25,000 MT GSC reporting threshold, the operator must report all stationary combustion emissions, including any associated with the SRU and wastewater treatment facility. The operator is not required to report process or fugitive emissions of CH_4 and N_2O from wastewater treatment or CO_2 from the SRU. However, the facility operator may report these emissions optionally (and flag them as such) within the Reporting Tool.

28. Q: Does **SF_6** used as an insulator for **electron microscopes** and for a plasma etching experiment at a university need to be included with the university's emissions report?

A: No. Only SF_6 from electricity power distribution equipment that the facility operator is required to maintain is required to be reported. See definition of "fugitive emissions" in section 95102 and 95111(a)(1)(J) of the regulation. Other major SF_6 sources are likely subject to ARB's regulation to reduce SF_6 emissions in non-semi conductor and non-utility applications (adopted 2/26/09). The university may choose to report these emissions optionally within the Reporting Tool.

29. Q: Can a facility designate emissions to the ***de minimis*** category from a source where a compliant monitoring system is **not in place by January 1, 2009** and use alternative emission estimation methods until such time that a fully compliant monitoring system is in place?

A: Yes, subject to verifier review. The regulation does not preclude the designation of a portion of a specific source of emissions or a subset of pollutants as *de minimis*. These emissions may not exceed 3 percent of the facility CO_2e emissions or
20,000 MT CO_2e in total.

30. Q: I am reporting purchased **indirect energy** used by my entire facility. Must I separately report indirect electricity used by the cogeneration system?

A: There is no need to separately report indirect electricity used by your cogeneration unit. If all indirect energy usage is reflected in your facility totals, you have met the requirements of the regulation.

GHG Reporting Tool

31. Q: Does the **principal contact** have to be the person who will **certify** the emissions?

A: The tool does not include a designation for a "principal contact" but instead allows designation of "facility managers." Two Primary Facility (or Entity) Managers may be designated within the tool for a facility, and an unlimited number of Alternate Facility Managers can be added to a facility by a manager. The first person to register a new facility is automatically assigned the role of Primary Facility Manager. Any of the "managers" has the ability to certify the emissions data. Facility managers may oversee the GHG emissions reporting, or may be actually inputting data themselves, based on the facility organizational structure. Managers may also use the tool to add "facility reporters" who have access to create and edit facility data within the Reporting Tool, but who do not have the capability to certify the data as complete and accurate.

32. Q: Can **facility managers** be changed in the future? For example, because the first person to register is automatically assigned as the Primary Facility Manager, can that be changed later on?

A: Yes; however we recommend that someone employed by the facility register the facility within the Reporting Tool (versus having a consultant do it). Within the tool, a user with facility manager privileges can assign different facility manager roles as needed to ensure that certification is performed by the appropriate facility personnel. A facility manager may also add other staff or consultants to the facility account as Facility Reporters. Please see page 2-18 of the User's Guide for more information. For changing "reporters" to "managers" and vice versa within the Reporting Tool, please contact ghgreport@arb.ca.gov for assistance.

33. Q: Can one user be associated with **multiple facilities**?

A: Yes. Users can either be added as a contact to existing facilities, or can register multiple facilities. Please see page 2-6 and 2-18 of the User's Guide, at http://www.arb.ca.gov/cc/reporting/ghg-rep/ghgtoolusersguide.pdf.

34. Q: Why does the Reporting Tool require a measured **high heating value** (HHV) if my general stationary combustion (GSC) facility is allowed to use the default HHV and emission factor in Appendix A?

A: A default HHV is only provided in the Reporting Tool for the fuel "Natural Gas-Unspecified (Weighted U.S. Average)." If you choose this fuel type, the default factors will be available to you in the emitting activity tab. The other natural gas fuel types will require input of a HHV, which can be obtained by your fuel supplier.

35. Q: Where do I enter the **monthly HHV** values in the Reporting Tool?

A: The tool does not provide the capability to include monthly HHV inputs. You will need to calculate your emissions on a separate spreadsheet, and then enter this 'precalculated" annual average HHV and your annual fuel use. Then, because you precalculated the CO_2 emissions, you would select "95125(c) - Precalculated" from the calculation method pulldown menu. You will be able to use the default emission factors in the calculation tool for your CH_4 and N_2O emissions.

36. Q: Many facilities are likely to hire **consultants** to assist them in preparing their online GHG reports. It would be helpful if your site had some form of **guest login** so that people other than actual reporting firms can login and test the site.

A: The GHG Tool Training Site has been set up for this purpose. Send ARB a request at ghgreport@arb.ca.gov and we will create a training account for you. For actual emissions reporting, facility managers can easily add consultants or others to their facility GHG Reporting Tool account(s), which allows access to the facility data. See page 2-18 of the tool Users Guide for instructions, here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghgtoolusersguide.pdf

37. Q: Is ARB's Reporting Tool the **only method** allowed to report to ARB, or can we generate the data required "manually" or some other way and forward to ARB?

A: The Board may take action in 2009 to require use of the Reporting Tool. Use of the tool is the best way for you, your verifier, and ARB staff to accurately estimate, communicate, certify, verify, and audit your GHG emissions. ARB understands there is a learning curve the first year. However, after entering all of the facility information the first year, it should be much easier to update the data in future years.

38. Q: Could you please tell me how many **decimal places** are required to be reported for fuel use, HHV, and greenhouse gases? For example, if I have fuel use data in scf, but I report it in the tool in Mscf, to how many decimal places should I enter the data? Also, as much of our data is pre-calculated, to how many decimal places should I report CO_2, CH_4, and N_2O?

A: Please use good scientific judgment when reporting emissions. In general, reporters will know the precision in their various fuel use and analytical measurements. If you are concerned with misrepresenting precision or rounding errors, you may report emissions with as much precision as your meter or calculation allows. Document your rounding so that a verifier will be able to reproduce your calculation.

39. Q: If a facility is both a cogeneration and a general stationary combustion facility, which do we designate as **primary sector** and which is **secondary**?

A: Your primary business determines your primary reporting sector, and you may look to your NAICS code for this. See the stepwise guide for electricity generating and cogeneration facilities for a full explanation. In some cases, operators of electricity generating facilities and cogeneration facilities will submit stand-alone reports. In other cases, electricity and cogeneration information will be submitted within the report of a power entity or another reporting sector, such as a cement plant, petroleum refinery, hydrogen plant, or general stationary combustion facility. Select “other” as the primary sector in the Reporting Tool when your primary business is not one of those listed.

40. Q: Can a cogeneration facility be classified as a **primary sector**?

A: Cogeneration is a secondary sector with one exception. The exception is when the operator’s primary business is energy production and the facility is 100 percent cogeneration.

41. Q: Reporters are able to **attach supporting documents** to their emissions report in the Reporting Tool. What should be submitted? Are certain documents expected to be attached (scans of electricity bills and gas bills for the year, Excel spreadsheets with calculations), or is this strictly optional?

A: The Reporting Tool may be used to provide information to ARB about related entities specified in section 95104(a)(8)(A). For the 2009 report, facilities with many devices may attach a spreadsheet (see Tool for format) to report required device-level fuel use. There is no requirement to submit copies of fuel bills or meter readings. Please note that any documents submitted to the tool may be subject to public release.

42. Q: Where do you obtain the **EIA identifier number** for an electricity provider?

A: ARB maintains a list of electricity providers and specified generating facilities with ARB identification numbers. Power entities reporting wholesale power transactions from specified sources are required to use ARB identification numbers for specified sources. You should use the ARB ID numbers whenever possible. If you do not see an ARB ID number for your provider or facility, please identify the facility by their EIA number if available, or ask ARB staff for assistance. The current list is posted here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/ghg-rep-power.htm

43. Q: For GSC facilities burning landfill gas, biogas, or anaerobic digester gas, may a default HHV be used to estimate emissions?

A: Yes, but only in limited circumstances, and not for electricity generation activities or cogeneration activities (except for abbreviated cogen reports). For GSC facilities subject to section 95115, the regulation specifies that, "Where a high heat value is not supplied for a specific fuel type in Appendix A, the operator shall use the method provided in section 95125(c), (d), or (h) to calculate CO_2 emissions." (§95115(b)(2)(C)). These methods require testing and measurement of the fuel characteristics or the use of generated steam to estimate emissions.

Because the regulation does not explicitly provide a default HHV for landfill gas, biogas, or anaerobic digester gas (i.e., biogases), the use of these measurement-based methods could be required. However, using information provided in Appendix A of the regulation, a default HHV for biogases may be readily derived. If measured HHV data are not available for biogases, the HHV of 524.39 Btu/standard cubic foot (scf) may be used. The default HHV is derived from Table 3 of Appendix A of the regulation which shows that 480,503 million Btu is equivalent to 916,301,950 scf. Dividing the Btu value by the scf value provides 524.39 Btu/scf. However, if the biogas is combusted for electricity generation or larger cogeneration activities, then the requirements from those sections of the regulation apply (§95111 and §95112) and the default HHV generally can not be used.

The default HHV may be used by facilities subject to section 95115 of the regulation and cogeneration facilities allowed to use abbreviated reporting. However, if available, it is preferable to use actual measured HHV data collected using methods specified in the regulation, rather than using the default value.

Combustion

44.Q: Are the GHG emissions produced from **flares and other destruction devices** (like VOC thermal oxidizers) considered combustion or process emissions?

A: Generally these are considered combustion sources. This issue is relevant not only to clarify which emissions must be reported, but also because the 25,000 MT CO_2 threshold that triggers reporting for GSC facilities is based on combustion emissions only, and not process emissions.

Clearly CO_2 emissions from the fuel (typically natural gas) that is burned to destroy organic gases must be included in determining applicability. For facilities subject to reporting, the CH_4 and N_2O from this combustion also must be reported. Because the CO_2 emitted from the organic gases destroyed in a combustion device is being emitted as a result of and "during an exothermic reaction of a fuel with oxygen" (per the definition at section 95102(a)(49) of the regulation), ARB has determined that such CO_2 should be included in the assessment of overall facility emissions. For facilities thus found subject to reporting, the CH_4 and N_2O from this combustion should also be estimated and reported. Further, process emissions are GHG emissions "other than combustion emissions occurring as a result of a process" (per section 95102(a)(158)). Because process emissions exclude combustion emissions, and combustion emissions include the CO_2 from organic gases destroyed by combustion, the CO_2 emissions from thermal destruction devices are not considered process emissions.

For these reasons we have established that CO_2 emissions from thermal destruction devices are to be included in the evaluation of the 25,000 MT CO_2 facility stationary combustion threshold, and these emissions (as well as CH_4 and N_2O) must be reported if the facility exceeds this threshold. CO_2 from biogas-fueled flares also needs to be tracked separately from the CO_2 from burning fossil fuels.

Because the combustion will be a combination of an input or pilot fuel and other organic gases to be destroyed, it is important to estimate and report the emissions from each fuel separately. An exception is when CEMS are used; in this case, the reported emissions do not need to be subdivided by fuel type. However, the quantity of each fuel burned needs to be separately reported.

45.Q: Section 95111(c)(8) for **start-up fuels** specifies which method(s) should be used for calculating stationary combustion CO_2 emissions. For our cogeneration plant, where we only use fossil fuel for start-ups, this sounds exactly how we utilize natural gas with the exception that the primary fuels are coal and petroleum coke with biomass as a supplemental fuel along with waste tires. Are we able to calculate natural gas CO_2 emissions under 95125(a)?

A: No. Because the majority of fuel combusted in this case is fossil fuel, section 95111(c)(8) does not apply. Section 95111(c)(8) applies to cogeneration and electricity generating facilities that combust primarily biomass-derived fuels.

However, the operator may consider whether the emissions from combustion of the natural gas start-up fuel can be designated as *de minimis*. When the sum of CO_2e emissions from the selected combustion sources (in this case start-up operations) is *de minimis,* the operator can use an alternate methodology. The accuracy requirement for fuel-based emissions calculation methods, including the requirement to report fuel consumption accurately to within +/-5 percent, is relaxed. Instead, operators must be prepared to demonstrate with "reasonable assurance" that the sum of reported *de minimis* emissions does not exceed the limits of 3 percent or 20,000 MT specified in section 951003(a)(6).

Fuel Measurements and Analysis

46.Q: Are utility gas meters adequate for meeting the +/-5 percent fuel measurement accuracy requirement? What documentation is required to demonstrate **accuracy within +/-5 percent**?

A: Utility (retail) gas meters are assumed to meet the +/-5 percent fuel measurement accuracy requirement because they are controlled for revenue collection purposes. Fuel purchase records, provided by the supplier, will typically be sufficient for estimating facility fuel consumption. Documentation is not necessary to demonstrate accuracy of meters installed and maintained by the utility, and the facility operator subject to GHG reporting is not required to maintain calibration or maintenance information for the "revenue" meter. However, during verification, this information could possibly be requested from the fuel supplier if needed to evaluate fuel use accuracy. See Guidance for Fuel Analytical Data Management in Appendix A of the *Instructional Guidance* document.

47. Q: Please give examples of how the availability and **accuracy of fuel meters** determine when an operator needs to install fuel meters, when to report device level fuel consumption, and how to set up emitting activities.

A: See Attachment 1 for detailed examples. If emissions are reported using a fuel-based methodology, emissions must be based on fuel measurements accurate to +/-5 percent. However, if an operator of an electricity generating facility has met this requirement at the facility level, the operator does not necessarily need to achieve the same level of accuracy when reporting sublevel emissions for individual electric generating units. Accuracy requirements do apply when reporting for secondary sectors embedded in larger facilities.

If the operator is able to meet the accuracy requirement when reporting sublevel or secondary sector emissions, then the operator can mark these emitting activities as "summed' and will not need to duplicate reporting at the facility level because the sublevel emissions will also be summed to the facility level in the operator's summary report.

The operator is required to report fuel consumption to the lowest level of metering. If the sublevel reporting of emissions and fuels accounts for the lowest level of fuel metering, there is no need to duplicate reporting by setting up fuel devices at the facility level. If, however, the emitting activities set up by the operator do not reflect the lowest level of metering, then the operator will need to set up devices to report fuel consumption as measured to the lowest meters. Device level reporting of fuel consumption does not need to meet the +/-5 percent accuracy requirement. See Attachment 1 for detailed examples.

48. Q: May **gas chromatographs** be used for estimating high heat value (HHV) when using method GPA Standard 2261-00 provided in section 95125(c)(1)(B) of the regulation?

A: Yes. Note 2 of the GPA 2261-00 states that, "Any gas chromatography is acceptable for the analysis of natural gas as long as the specifications for repeatability and reproducibility in Section 9 over the component ranges listed in Table 1 are met or exceeded."

49. Q: Several of the of the **ASTM methods** cited in the regulation have been or are in the process of being **updated**. Laboratories generally use the updated methods. Will use of the updated methods be permitted under the regulation?

A: As ARB staff becomes aware of updated methods we will review them for consistency and equivalence with the methods cited in the regulation. Where it can be determined that the modifications in the laboratory method would not materially affect the outcome of the analysis for the test in question, use of the updated method will be permitted. Where results between the cited and updated methods would differ, a regulation change may be needed before the updated method could be accepted. Operators would need to apply results from the cited version of the method in the interim.

50. Q: Regarding **hydrogen plant** stationary combustion emissions, if the fuel flow meter in the hydrogen plant is not being used to calculate emissions from refinery fuel gas combustion, does the hydrogen plant flow meter need to meet the **+/-5 percent accuracy** requirement? The example given was the case where a flow meter at the upstream fuel gas mix drum is used to calculate the emissions from refinery fuel gas and this meter meets the +/-5 percent accuracy requirement and includes fuel gas subsequently combusted in the hydrogen plant.

A: Because the hydrogen plant is required to separately estimate its greenhouse gas emissions, the fuel use for the plant should be measured to +/-5 percent. This requirement does not currently apply to feedstocks.

51. Q: What type of **natural gas testing** fulfills the monthly testing/sampling requirement?

A: The testing requirement varies by sector. If the facility falls into the General Stationary Combustion sector, the higher heating value (HHV) or carbon content testing of the natural gas is not currently required, and the heat values provided in Table 4 of Appendix A may be used with a default emission factor as shown in 95125(a) for natural gas, unspecified (Weighted U.S. Average).

For other sectors, including GSC facilities with electricity generating units or cogeneration systems, either HHV or carbon testing is required based on the specific requirements in the regulation (unless CEMS are used). The testing frequencies for natural gas (gaseous fuels) are provided in sections 95125(c) and (d) of the regulation, and are generally monthly.

Facility operators may also use the monthly higher heating values for pipeline natural gas (HHV between 975 and 1,100 Btu per scf) provided in their billing information by their utility. The methods used by the utilities for testing pipeline quality natural gas are considered sufficiently rigorous to meet ARB's requirement for greenhouse gas reporting. Billing records from the utilities are considered sufficient documentation for verification purposes.

52. Q: If you burn natural gas at a GSC facility and you know the **HHV for natural gas** from information **provided by the supplier**, can you still use the equation in 95125(b)(3) to estimate CH_4 and N_2O, or would you be required to use the equation under 95125(b)(2) and measure the HHV monthly according to 95125(c)?

A: HHV provided by a fuel supplier can be used under the requirements of 95125(c)(1)(B). Also, see 95125(c)(1)(A) where the operator may elect to use HHV provided by the supplier. You may use HHV from your supplier to calculate CH_4 and N_2O according to 95125(b). We are also looking at cases where suppliers may have used other HHV test methods, to examine their equivalence to the methods specified in the regulation.

53. Q: Is a **belt or conveyor scale** the only acceptable approach under the regulation for **measuring solid fuels**? Would a fuel pile inventory approach be acceptable? The site does not currently employ belt or conveyor scales, but a gate scale weighs all fuels brought on-site to the facility. Periodic (quarterly) fuel pile surveys are used to quantify the existing fuel pile in order to make adjustments for fuel received vs. combusted in three units.

Would the calibration requirements regarding the gate scales need to match a quarterly calibration schedule identified for the belt/conveyor scales or would it default to the requirements of other fuel measurement devices in which calibration is required consistent with manufacturer's recommendations to maintain the specified +/-5 percent accuracy?

Would one of the fuel pile surveys need to occur exactly on December 31st to allow for an annual inventory adjustment? The site currently conducts a survey in early December before closing the financial books at the end of the year.

A: Solid fuels may be measured using any procedure sufficient to quantify fuel use accurately, including gate scales. The calibration schedule in section 95103(a)(9) applies only to belt or conveyor scales when the operator is doing the fuel measurement, rather than the fuel supplier. For fuel pile surveys, a year-end "stock" estimate may be made if a fuel audit does not coincide with the end of the calendar year. In this case, the procedure must be well documented for review by a verifier.

54. Q: Is it acceptable to use **truck scale tickets** to confirm **weight of solid fuel burned**? If the truck weight scales are located at the fuel supplier, and owned by the fuel supplier, is the facility responsible for determining the accuracy of the scales, with requirements for calibration and maintenance?

A: It is reasonable to expect that truck weight tickets would meet the fuel measurement accuracy requirements of the reporting regulation, since they are the basis of a commercial transaction similar to gas revenue meters. In addition, the regulation does not require you to calibrate the scales used by an off-site fuel provider. A verifier may request access to scale calibration records, so acquisition of those records by the reporting facility is recommended though not required by the regulation.

Fuel consumption may extend beyond the immediate question of whether the weighing method is accurate on an annual basis. For solid fuels analyzed by the operator the regulation requires the operator to conduct a test at least monthly for carbon content from a composite of weekly samples per section 95125(d). To weight these monthly carbon content values correctly over the course of a year, the operator needs to know how much fuel was consumed in each given month. This included knowledge of how much fuel is on hand at the beginning and end of each month, and balancing those to ascertain how much was burned that month. Truck weight tickets tell you the weight of each load, but not how much fuel is burned in a given month unless whole loads match up to the beginning and end of the month. The “month” does not need to be a specific calendar month, but should be regular intervals of fuel estimation approximately twelve times per calendar year. Note that this requirement does not apply when carbon sampling is conducted by the fuel supplier following the appropriate ASTM sampling method.

55. Q: Can fuel **carbon content** that is provided by a fuel supplier be used in the emissions calculation for solid fuels, or must the operator separately collect **weekly samples** to conduct a monthly test of carbon content?

A: The specification for a monthly test using weekly sub-samples in section 95125(d)(1)(B) applies when carbon content is determined by the operator rather than the fuel supplier. As long as the fuel supplier is conducting sampling in accordance with the industry standard ASTM method for the fuel in question and transmitting the correct carbon values as determined for each shipment of fuel delivered to the operator, additional sampling is not required unless the operator has altered fuel composition (see following question). Note, however, that a verifier may seek documentation through the operator that sampling for the delivered fuel was conducted consistent with the standard laboratory practices for that fuel.

56. Q: Please explain the requirement for representative sampling of solid fuels when **fuel treatment** is conducted. Under what circumstances may samples be taken prior to fuel treatment?

A: Solid fuel samples collected and tested for higher heating value (HHV) or carbon content must be representative of the fuel combusted.[1] The first example below clarifies when sampling must be conducted *after* fuel treatment in order to conform to the regulation. Examples 2 and 3 illustrate circumstances when fuel sampling may be conducted *prior* to fuel treatment and meet the regulatory requirement.

Note that moisture content must be considered when evaluating whether a sample is representative of the fuel combusted during a particular time period. Solid biomass-derived fuels are reported in bone dry short tons and the emissions calculation must incorporate HHV (MMBtu/bone dry short ton) or percent carbon content on a bone dry basis. See following question about coal analysis, which also applies to other non-biomass solid fuels.

Example 1: The addition of chemical compounds to enhance flammability is an example of fuel treatment that may alter fuel-based calculations of GHG emissions. Samples must be taken ***after*** fuel treatment when additives alter the total heat in million Btus or the total carbon in metric tonnes.

Total heat, MMBtu = HHV in MMBtu/short ton of monthly composite sample x short tons of treated fuel combusted during the associated month

Total carbon, MT = % carbon content of monthly composite sample/100 x short tons of treated fuel combusted during the associated month x 0.9072 metric tonnes per short ton

Example 2: Samples may be taken ***prior*** to fuel treatment when GHG emissions of the additives can be accounted for separately from the fuel. For example, when the additional CO2e resulting from fuel additives is demonstrated to be within the facility's *de minimis* threshold, an alternate method may be used to calculate associated GHG emissions.

Example 3: Samples may be taken ***prior*** to fuel treatment when the nature of the fuel treatment will not change total GHG emissions. Examples include grinding, shredding, and crushing. This type of fuel treatment is not expected to change the resulting GHG emissions since 100% combustion is assumed in the ARB-specified emission factors.

[1] Section 95125(c)(1)(A)(4), for operators sampling solid fuels to support calculation of CO_2 combustion emissions using measured heat content, specifies "The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion." Similarly, section 95125(d)(1)(B), for operators sampling solid fuels to support calculation of CO_2 combustion emissions from measured carbon content, specifies "The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical characteristics combusted during the sample week."

57. Q: Which **percent carbon** value from the **coal analysis** do we use for calculating mass emissions from the fuel: as-received, air-dried, or dry (desiccated)?

A: Coal carbon content should be expressed in the same terms as the weight of coal measured. Thus, if the weight of coal measured before combustion is a wet weight, you should use this value and the wet weight carbon fraction to calculate CO_2 emissions.

58. Q: Are **self-calibrating meters** subject to accuracy testing if it is original equipment and the equipment manual is available?

A: The regulation does not specify a test protocol for fuel meter accuracy. Operators should consult original equipment manufacturer (OEM) specifications to ensure meters are installed and maintained to accuracy specifications within +/-5 percent.

59. Q: If the facility does not have devices for direct measurement, are **fuel purchase records** sufficient to satisfy the fuel use measurement accuracy requirement, or does the facility need to ensure that the fuel meter is calibrated within +/-5 percent?

A: Fuel purchase records will typically be sufficient for quantifying fuel use for GSC facilities if the on-site meter does not meet the accuracy specification. A verifier may request calibration documentation from the fuel supplier (via the facility) if there is a question. Particularly for biomass or waste-derived fuels, or fuels provided by a non-commercial supplier, a verifier may need to evaluate whether the fuel measurement mechanisms are sufficient.

Biomass-Derived CO_2 Emissions

60. Q: Under section 95125(h)(2) does the regulation allow for **fuel sampling** as an option, in lieu of exhaust sampling, to determine **biomass** emissions?

A: Yes, the regulation allows for calculation of biomass emissions from fuel sampling as an alternative to emissions sampling, to the extent testing of a fuel type is supported by ASTM D6866. Fuel samples collected for analysis should be representative and unbiased, consistent with other requirements of the regulation. Note that the requirement in section 95125(h)(2) to gather a sample over a 24-hour period is for cases where exhaust samples are gathered for analysis, and would not apply when a fuel or fuel mixture is analyzed directly. The other collection and calculation provisions in section 95125(h)(2) do apply to fuel samples, including the requirement that the ASTM analysis be conducted at least every 3 months.

61. Q: Can the **ASTM D6866** test be used by operators to estimate the **biomass fraction** of either individual fuels or fuel mixtures that are at least 5 percent biomass by weight?

A: Yes, to the extent this is consistent with and supported by the ASTM test method. The regulation specifies the circumstances in which the D6866 analysis must be performed, but does not limit its use in other circumstances.

62. Q: Determining CO_2 emissions from **biomass-derived fuels** or municipal solid waste (MSW) requires using ASTM Method D6866 and collecting gas samples every 3 months over at least 24 consecutive hours. We are currently sampling from the exhaust stream entering the CEMS at a facility. The facility does **calibrations of the CEMS** everyday, shutting down the exhaust flow daily for about an hour. Our current sampling scheme is to sample for a five day period, with the sampling train shut off during the calibration process. This gives us a 4 to 5 day **composite sample**, which seems to provide a good sample, but it is not over 24 consecutive hours. Is this a problem?

A: Section 95125(h)(2) states that the exhaust gas sample must be collected over at least 24 consecutive hours, so you should plan to do this for one full day at three-month intervals. If a one-hour daily shutdown is part of normal operations, the value recorded for the exhaust during that hour may be zero.

63. Q: My facility is a wastewater treatment plant with a requirement to report as an electricity generator. We co-fire anaerobic digester gas (**biogas**) with natural gas in our reciprocating engine. How do I calculate my CO_2 emissions from this emitting activity?

A: Section 95111(c)(7)(B) of the regulation, for calculating CO_2 emissions for co-fired fuels, refers to section 95111(c)(5) for biogas and section 95111(c)(1) for natural gas. For biogas, section 95111(c)(5) specifies methods 95125(c) higher heating value (HHV), 95125(d) carbon content, or 95125(g) CEMS. For natural gas, see section 95111(c)(1). If the natural gas has a HHV in the range of $975 \leq HHV \leq 1100$ Btu/scf, you may use the same methods as biogas. If the HHV of the natural gas falls outside that range, you cannot use method 95125(c) based on HHV.

If you measure the volume of digester gas combusted (scf) and higher heating value (HHV in Btu/scf), these measurements can be used to calculate all three required GHGs for stationary combustion: CO_2, CH_4, and N_2O. To calculate CO_2, use method 95125(c) and the "biogas" default factor (104.06 kg CO_2/MMBtu) from Table 4 of Appendix A. To calculate CH_4 and N_2O, use method 95125(b) and the ARB default factors (g/MMBtu) for "digester gas" in Table 6.

If you measure the carbon content of your biogas, we encourage you to use the method in section 95125(d) to calculate CO_2 emissions. Using the measured carbon content for your fuel will usually produce a more accurate emissions calculation.

64. Q: The regulation allows a choice of fuel-based methods for estimating CO2 from combustion of biogas, including landfill gas and digester gas. Which is more accurate, the method using measured higher heating value (section 95125(c)) or measured carbon content (section 95125(d))?

A: The method using measured carbon content is more accurate for biogas. Under both methods, CO2 from combustion and the pass-through CO2 are included in the reported biomass-derived CO2. The heating value method uses an emission factor for biogas that assumes CO2 from combustion and the pass-through CO2 are in equal proportions. In cases where CH4 is greater than 50 percent of fuel volume, CO2 emissions will be overestimated. In cases where CH4 is less than 50 percent of fuel volume, CO2 emissions will be underestimated. Though either method is allowed, carbon content testing will avoid this problem and provide a more accurate estimate of CO2 emissions.

CEMS (Continuous Emission Monitoring System)

65. Q: The CEMS CO_2 emissions data for a cogeneration facility is monitored using a CEMS that meets the operator's requirements per 40 CFR Part 60. The **CEMS measurements rotate from stack to stack** every 7 minutes. Does this comply with the ARB GHG reporting regulation?

A: If the CEMS complies with the U.S. EPA requirements you have specified, it is considered acceptable for GHG reporting in California. See guidance for method specified in section 95125(g) in chapter 13 of the Instructional Guidance document.

66. Q: My facility has a CEMS system that meets requirements under 40 CFR Part 60 but it **measures O_2 concentrations instead of CO_2**. Can I use the CEMS data to determine CO_2 emissions?

A: If your facility combusts biomass or fossil fuels, section 95125(g) allows you to use the O_2 concentration and flue gas flow measurements to determine CO_2 emissions using the methodology provided in 40 CFR Part 75, Appendix F. If you combust biomass, your annual source testing must demonstrate that when you compare the CO_2 concentrations you calculated using O_2 concentrations to measured CO_2 concentrations, the comparison meets the Relative Accuracy Test Audit requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

If your facility is subject to 40 CFR Part 75, you are required to report CO_2 emissions in annual metric tonnes based on the CO_2 data you give U.S. EPA to meet the Part 75 requirements. If your facility installs a new CEMS, you are required to measure CO_2 concentrations and flue gas flow.

67. Q: Is the method to allow CO_2 reporting using **O_2 CEMS**, which our cogeneration facility uses to meet the Title 5 Part 60 requirements, **allowed to be used into the foreseeable future**?

A: Future amendments to the specified GHG calculation and reporting methods would be considered following a public participation process to inform any changes in accepted methods. Please see chapter 13 of the *Instructional Guidance,* which discusses section 95125 of the regulation. If you choose to install a new CEMS system or CO_2 CEMS components, it must be operational for purposes of emissions reporting by January 1, 2011.

68. Q: Does the ARB provide guidance or sample calculations **converting O_2 to CO_2** using the methodology in 40 CFR Part 75 Appendix F?

A: Not currently. However, ARB's Training and Compliance Assistance Program offers a class in CEMS that you may be interested in (http://www.arb.ca.gov/training/401.htm).

69. Q: Will reporters have the **option of using better technologies** for reporting emissions as they become available?

A: The reporting regulation would need to be amended first to allow for different types of reporting than what is currently allowed under the regulation. Please contact ARB staff if you need to determine if a specific methodology meets the requirements of the reporting regulation.

70. Q: If my facility is reporting emissions using a CEMS methodology, do I still need to **report fuel consumption**? Does my fuel meter need to meet the **+/-5** percent **accuracy** requirement?

A: You must report your fuel consumption, but because fuel use is not part of your emissions calculation, your fuel meter does not need to meet the +/-5 percent accuracy requirement.

Source Testing

71. Q. When can I use source test data to calculate emissions? Could I use source test data to calculate emissions for the **whole reporting period** as long as I had no significant changes to the process during the reporting period?

A. You may elect to use source test data based on a source/site test plan pre-approved by ARB for calculating CO_2 emissions from geothermal electricity generating facilities and from facilities that combust biomass solid fuels or waste-derived fuels (including municipal solid waste). In addition, source test data can be used to determine CO_2 process emissions from sulfur recovery, and N_2O or CH_4 combustion emissions for all fuel types.

You may use source test data to calculate emissions if fuels and processes are consistent. The source test plan submitted to ARB must include the period that the emissions estimate is intended to cover and an explanation about how this characterizes the facility operation. The underlying assumption is that data collected and factors developed from source tests would be used to estimate the emissions for the entire reporting period. If the test protocol and resulting data do not adequately address variability throughout the year, then it probably should not be used to calculate annual emissions. This question should be resolved at the time the source test plan is reviewed and approved.

Because source testing is a series of discrete sampling events used to approximate emissions over a much longer time frame than the actual sampling duration, source test data are used to estimate facility emissions both before and after the actual source test event(s).

72. Q: May I submit a **source test plan** for **several facilities**?

A: Yes. We encourage the use of source test data for multiple facilities and sources. However, ARB will need to approve all initial source test plans before testing begins.

Electricity Generating and Cogeneration Facilities

73. Q: When determining if a **cogeneration** system is subject to reporting, **what emissions information is included**? Is it the **distributed emissions** (CO_2) for electricity generation? Do I exclude the distributed emissions for thermal energy?

A: You will use the distributed emissions equations to compare distributed emissions (CO_2) for electricity generation to the reporting threshold. Include process CO_2 and biomass-derived CO_2 from stationary combustion, if applicable. See Chapter 9 of the *Instructional Guidance* for a full explanation.

74. Q: Would stationary combustion emissions from a cogeneration system or generating unit under common **operational control** within a larger facility (such as an oil and gas production facility) be included when assessing whether the larger facility exceeds the 25,000 MT CO_2 **reporting threshold**?

A: Yes. Electricity generating units (EGUs) and cogeneration emissions are included with other specified emissions when comparing total facility emissions to the reporting thresholds in section 95101 of the regulation.

75. Q: In the following scenario, can the **abbreviated cogeneration report** specified in section 95112(c) be submitted? Does the cogeneration system still meet the definition of the term "self-generation"?
- nameplate generating capacity < 10MW
- uses the electricity generated on-site, except that a small amount of electricity goes to the grid

A: Yes. An abbreviated report is an option when it is clear that electricity sold to the grid is incidental and the cogeneration system is dedicated to serving the on-site demand. Note that GSCs and other larger facilities with cogeneration are not eligible to submit an abbreviated report.

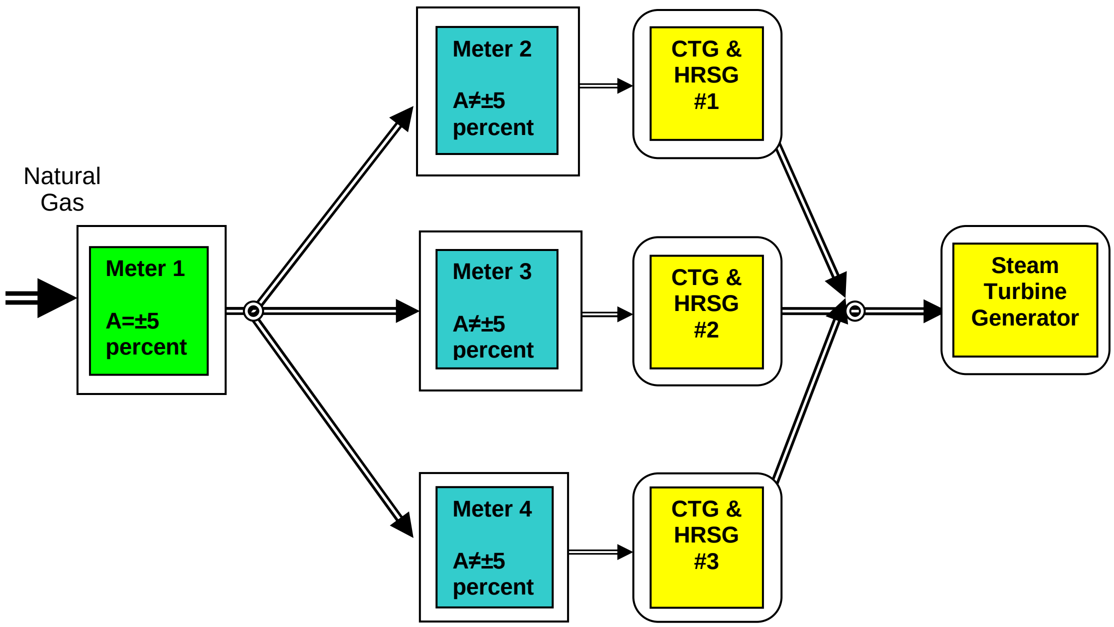
76. Q: What is the procedure for reporting **emissions and fuels data** for a **combined cycle power plant**?

A: The combined cycle electricity generating system is considered a single "generating unit" for purposes of reporting GHGs. [The definition from ARB's GHG Reporting Regulation reads: "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.]

A 3-on-1 design is used as an example, illustrated below. The natural gas plant consists of three combustion turbines that drive electricity generators. Hot exhaust gas from each combustion turbine passes through an associated Heat Recovery Steam Generator (HRSG). The HRSGs make use of high temperature exhaust gas to heat water (heat exchange) and produce steam. Steam from the three HRSGs is combined to run a single steam turbine generator.

Two options are described to set up the emitting activities and fuel measurement devices are described, based on fuel meter accuracy considerations. In this example, the most accurate fuel meter is upstream of the combustion turbines. ***In the case where a fuel-based calculation is used and emitting activities are summed to the facility level, be sure the GHG calculations are based on fuel consumption data that are accurate to within +/-5 percent***.

Option 1: Set up one emitting activity based on the most accurate meter to include the fuel combusted by all three combustion turbines. You will select "Combined Cycle Power Plant" under emitting activity type and designate the aggregation level as "summed." Less accurate meters are located at each combustion turbine, so identify these meters under the "Devices" tab in the Reporting Tool.



Option 2: If you have a preference, you may set up four "emitting activities" under this single generating unit. This will allow you to report fuel consumption at the upstream meter for the combined cycle power plant as a whole, as well as for each combustion turbine. Since the emissions calculations for the individual combustion turbines are not based on fuel consumption monitoring accurate to within +/-5 percent, report these emitting activities as "supplemental." Under this option, you will not need to report the combustion turbine meters under the "Devices" tab.

77.Q: What is the procedure for setting up and reporting **energy and production data** for a **combined cycle power plant**?

A: Step 1: You will select the "Energy Production" category under the "Energy and Production" tab in the Facility Information Module. This will allow you to enter your net power generation at both the facility level and generating unit level when you access the Annual Reporting Module.

Step 2: At the generating unit level for the "combined cycle power plant," you will report, in a single data entry field, nameplate generating capacity (MW) that is the sum of all four generators (3 combustion turbine generators plus one steam turbine generator). This is reported in the "Facility Information" module under the "Generating Units" tab. You will do the same for net power generated (MWh). At the generating unit level for the "combined cycle power plant," you will report, in a single data entry field, net power generated (MWh) that is the sum of all four generators. Generating unit level net power generated is reported as a “new submission” in the Annual Reporting module. Select “Generating Unit” for the reporting level and “Energy and Production” for the submission type.

Step (3): Nameplate generating capacity and net power generated must also be entered for the facility level. Because you have one generating unit, the facility level information will be the same as the generating unit information. ***You do not need to set up redundant “emitting activities” at the facility level in order to report this information***. Facility level nameplate generating capacity is under the “Facility Details” tab in the Facility Information Module. Facility level net power generated is reported as a “new submission” in the Annual Reporting module. Select “Facility” for the reporting level and “Energy and Production” for the submission type. Please contact ARB staff if you need assistance.

78. Q: In the following scenario, is a **cogeneration facility subject to different reporting requirements** than a general stationary combustion facility?

a. Under the operational control of an electric service provider (ESP)
b. Total emissions from all combustion sources >25,000 MT CO_2/yr
c. Topping cycle plant
d. Thermal energy is provided to a separate end user (separate operational control) that owns the land on which the cogeneration facility is located

A: The ESP is subject to section 95111 and will report as a retail provider that also operates a cogeneration facility. The ESP’s responsibility is limited to facilities it operates and to activities related to providing energy to its end user customers, including auxiliary boilers, if applicable. In this example, the primary sector for this facility is cogeneration.

79. Q: If I operate **three electricity generating units** on the same property that are each under 1 MW and under 2,500 MT CO_2/year, do I need to submit a greenhouse gas data report?

A: Scenario 1 - the three units combined do exceed 1MW and 2,500 MT CO_2/year. In this case, you would report for your generating units under section 95111.

Scenario 2 - the combined units do not exceed the thresholds and the generating units are the only combustion sources that would potentially trigger the mandatory reporting requirement. In this case, you are not required to report.

Scenario 3 - the combined units do not exceed the thresholds, but they are part of a general stationary combustion facility or some other type of facility, such as a refinery, that is required to report. In this case, you are required to report emissions for each of these units as a simple combustion source. You would not need to meet the requirements of section 95111.

80. Q: My site has two electricity generating units; one sells electricity to the grid and the other generates electricity for use on-site in the plant. Would I **add the two together** for reporting purposes?

A: In this case the distinction between the two generating units is made when reporting either electricity consumed on-site or electricity provided or sold. You will report nameplate generating capacity and net power generated individually at the generating unit level as well as added together at the facility level. This applies alike to electricity generating units and cogeneration systems. Note: "cogeneration systems" are also considered "generating units" for purposes of reporting.

81. Q: For a cogeneration plant, is there a difference between "**net power generated**" and gross power generated?

A: "Net power generated" means the gross generation minus station service or generating unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, "net power generated" is intended to include on-site consumption of electricity for the purposes of a production process, power provided directly to end users, as well as wholesale power provided to the grid.

82. Q: Does **electricity consumed on-site** refer to cogeneration electricity consumed on-site or both cogeneration electricity and grid electricity consumed?

A: Section 95112(a)(3)(C) refers to electricity generated by the cogeneration system and consumed on-site. Grid electricity consumed is reported in kWh as electricity usage (section 95112(a)(6)).

83. Q: A facility whose primary business is neither electricity generation nor cogeneration includes either an electricity generating unit (EGU) or a cogeneration unit that exceeds 1 MW and 2,500 MT CO_2. The total facility emissions are less than 25,000 MT CO_2. Does the operator report emissions from **all combustion sources** at the facility or only **emissions associated with electricity production**? What if the total emissions exceed 25,000 MT CO_2?

A: The operator is required to report emissions and other non-emissions data required in section 95111 or 95112 related to energy production and distribution because the EGU or cogeneration unit exceeds the reporting thresholds. Reporting would also extend to electricity generation and distribution activities that emit fugitive emissions of HFC or SF_6.

If the operator is not required to report emissions from other sources at the facility because the facility's total emissions fall below the reporting threshold for general stationary combustion facilities, the operator would not need to report emissions for separate boilers which may be used continuously, intermittently, in standby mode, or for auxiliary thermal energy production.

However, if the annual emissions from the EGU or cogeneration system in combination with all other stationary combustion sources at the facility are ≥25,000 MT CO_2, the facility is also subject to the reporting requirements of a general stationary combustion facility (found in section 95115), and all stationary combustion emissions must be reported.

84. Q: For an operator whose primary business is cogeneration, does natural gas usage need to be reported separately for combustion in a **backup boiler** and a **startup fuel for the main facility boiler**? The backup boiler is used only for thermal energy production and not electricity generation. The main facility boiler is used for both electricity generation and thermal energy production.

A: Emissions for the startup fuel are included in the total cogeneration emissions and in the distributed emissions calculations. Emissions from the backup or auxiliary boiler are not. For this reason, the fuel quantities and associated emissions are reported separately.

85. Q: A facility emits ≥ 25,000 MT CO_2 and includes EGUs or cogeneration units. Does the **operator quantify emissions** based on section 95111 or 95115 for those emissions sources not associated with energy production?

A: Emissions related to energy (electricity or thermal) production and distribution must be calculated using the methodologies specified in section 95111 or 95112, as applicable. The exception is EGUs or cogeneration units that combined do not meet the reporting thresholds for electricity generating or cogeneration facilities. For these small units and for all other emissions sources at the facility, the operator would report emissions according to the section of the regulation that pertains to the operator's type of facility. These sections are 95110 for cement, 95113 for refineries, 95114 for hydrogen production, and 95115 for general stationary combustion facilities.

86. Q: Are **two separate cogeneration facilities** operated by a retail provider required to submit a **separate** GHG emissions report to CARB, or would the GHG emissions information be submitted under a comprehensive report from the electric service provider for both sources?

A: You will be able to submit a comprehensive report as a retail provider and include separate emissions reports from your cogeneration facilities. The emissions will still be by individual facility, but the submittal will include both sets of facility data.

87. Q: Which **NAICS Code** should I use if I operate a **cogeneration** facility?

A: Please select the NAICS Code that best describes the primary business at your facility. If you are an electric service provider that operates an electricity generating facility, a NAICS Code of 221112 (fossil fuel) may be the appropriate description. A specific NAICS code is available for wastewater treatment under the utility category. Universities and colleges have a specific code as well.

88. Q: At my cogeneration facility, I have two small **refrigeration units with HFCs**. How do I report these if there is no release?

A: You only need to report HFCs used in cooling units that support power generation or are used in heat transfers to cool stack gases.

89. Q: How do you report **distributed emissions** for the following scenario? The exhaust from a gas turbine is routed through an HRSG and heat is used to produce steam. Of the total, one portion is re-injected into the gas turbine for power augmentation and emissions control and the remainder is supplied to an industrial process.

A: For distributed emissions estimates, please refer to Chapter 9 of ARB's *Instructional Guidance*. The remainder supplied to the industrial process is considered useful thermal energy and is converted to MMBtu for the report year. Steam used for power augmentation or NOx control, sent to a de-aerator, sent to a cooling tower, or vented is not considered useful thermal energy. Only steam or heat provided to an end user or used on-site for production purposes or space heating is considered useful thermal energy.

90. Q: If a facility with a cogeneration system triggers the need to report as a general stationary combustion facility, should we identify the cogeneration as a **secondary sector** if the cogeneration facility **does not trigger reporting by itself** (under 95101(b)(7))?

A: No, you should not designate the cogeneration system as a "secondary sector" in the Reporting Tool. That would incorrectly trigger other reporting requirements in the Reporting Tool which are not required to be reported. You can include stationary combustion emissions from the cogeneration at the facility level and use the methods allowed for GSCs.

If you would like to report the cogeneration emissions separately (as either "added, supplemental, or optional"), you can set up a facility level emitting activity and give it a meaningful name. Please do not set up the emitting activity under the "Generating Unit" tab, as that would also incorrectly trigger other reporting requirements. Be mindful in choosing whether you report as either "added, supplemental, or optional" and the data accuracy requirements as well as calculation methods expected. The emitting activity category is "stationary combustion."

91. Q: If I have equipment that uses **SF_6** but I **contract another firm/entity** to conduct maintenance for me, do I need to report fugitive SF_6 or is the other firm/entity required to report?

A: If you are responsible for maintaining the equipment in proper working order you are required to report fugitive SF_6 and should work with your contractor to carefully track the usage and annually estimate these emissions.

92. Q: Is there a cut off (reporting threshold) for generators to report **power exports**?

A: No. All electricity exports must be reported, if known.

Power Entities with Electricity Transactions

93. Q: If a retail provider **does not operate any electricity generating facilities**, is the retail provider still required to submit a greenhouse gas data report?

A: Yes. All retail providers are required to report even if they do not operate a generating facility or unit. They also report if their only resources are hydroelectric, nuclear, solar, or wind powered facilities. In these cases the retail provider reports as a power entity only. Power entities report non-emissions information on their power transactions, non-emissions information on facilities they own or operate, and fugitive emissions of SF_6 emitted from power transmission lines, substations, and other equipment located inside California that the retail provider is responsible for maintaining.

94. Q: Is the Purchasing/Selling Entity (PSE) at the **first point of delivery** (FPOD) defined by what is on the North American Electric Reliability Corporation (**NERC) tag**?

A: Yes.

95. Q: Retail providers are required to report **imported power** when they are the **first deliverer** and also when they are not the first deliverer. In the latter case, the first deliverer is another entity called a marketer. Since marketers must also report all power they import into CA, how do you ensure there is not any **double counting**?

A: Retail providers report imports/exports and power transactions inside California. They are required to indicate when they are the purchasing/selling entity at the first point of delivery inside CA. Marketers report imports/exports only when they are the first deliverer. When ARB analyzes the data, we will look at first deliverer data separately from other kinds of transactions. First deliverer data will include transactions by retail providers and by marketers. A separate data set will include all power transactions by retail providers. The two datasets will not be combined.

96. Q: The regulation requires retail providers that hold contracts entitling them to a specified **percentage of a facility's generation** to treat the power as being from a **partially owned facility**. If the contract identifies a specific amount of power in MWh per year, would the facility be considered partially owned?

A: No. A facility is considered partially owned only if the percentage is stated in the contract or the contract is for all power generated. For example, if the contract is for 50,000 MWh per year, the power purchased or taken from the facility is reported as a transaction only. The retail provider is not required to "calculate" an ownership share at the end of the year. If the contract is for all the power generated by the facility, that is clearly 100 percent. The retail provider reports the power taken as a transaction in MWh per year and also reports an ownership share of 100 percent. If the contract states 50 percent, the retail provider reports the power taken as a transaction in MWh per year and also reports the ownership share as 50 percent.

97. Q: A retail provider has a contract to take **50 percent of power generated** from a resource mix of multiple facilities. Would the retail provider report ownership share in multiple facilities?

A: No. The requirement to report ownership share pertains to contracts with a specified facility only. A resource mix is considered unspecified power.

<u>Cement Plants</u>

98. Q: In the regulation, the carbon content test method is clearly defined for coal and coke, solid biomass-derived fuels, waste-derived fuels, petroleum-based liquid fuels, and liquid waste-derived fuels. Where is the **heating value test** method for **coal?**

A: Section 95110(d)(2) specifies that cement plants shall calculate CO_2 emissions using the measured carbon content in section 95125(d). The regulation does not provide for a higher heating value method for coal.

99. Q: Does the regulation **define test methods** for CaO and MgO content in the clinker and non-carbonate CaO and MgO content in the clinker? Regarding the non-carbonate percentages, is this an analysis of the clinker or of the materials used to produce the clinker? For example, if fly ash is used as a component of the kiln feed mix, is the **fly ash tested** for non-carbonate CaO and MgO content or is the clinker tested?

A: Section 95110(c)(1)(A) of the regulation describes the derivation of the clinker emission factor but does not prescribe a particular test method for determining the respective CaO and MgO contents. Although the regulation does not prescribe a method at this time, the Western Climate Initiative Essential Requirements for

Reporting and the U.S. EPA proposed reporting rule are expected to require use of X-ray fluorescence, so you may wish to begin using that method as soon as practicable. All measurements are taken of the clinker and not of the feedstock. The variables are explicitly defined as the non-carbonate CaO content of clinker and the non-carbonate MgO content of clinker.

100. Q: How do I account for the **recarbonation** phenomena for clinker or cement **while in storage** - should it come as a deduction from total emissions?

A: This is not accounted for in the regulation or in the Reporting Tool. You should not include this in your emissions report.

101. Q: Does the regulation apply to **cement bagging** facilities that do not manufacture cement?

A: Probably not. If cement is being transferred and bagged, but not manufactured, the facility would not qualify as a cement plant. The facility would only be subject to reporting as a general stationary combustion facility if it emitted at least 25,000 MT of CO_2 emissions from stationary combustion.

102. Q: Operators that burn **tires** are given the option of using section 95125(c) requiring a measured heating value with a default carbon emission factor, or using the method from 95125(d) and measuring carbon content directly. Tires have significant operational, technical, and safety factors to consider when sampling and analyzing them. We do not currently have a **method to sample whole tires**. How do we handle this?

A: Section 95110(d)(7) requires cement plants that combust waste-derived fuels, such as tires, to calculate CO_2 emissions using the method provided in section 95125(c), or section 95125(d), or section 95125(h)(3) for the 2008 data, reported in 2009 and for subsequent years. However, the regulation does not prescribe a particular method to sample whole tires. Some facilities have developed a representative sampling procedure for whole tires that involves obtaining tire cross-sections from a representative group of tires. The tire samples are then homogenized prior to laboratory analysis. ARB staff will work to assist facilities in developing appropriate sampling protocols.

Refinery and Hydrogen Plants

103. Q: Due to the definitions of naphtha, distillate fuel oil and diesel fuel, are **diesel** and **gasoline tanks** subject to the **fugitive emissions reporting** requirements?

A: Refineries are not required to calculate and report emissions from diesel and gasoline storage tanks. You must calculate and report emissions from storage tanks containing crude oil, naphtha, asphalt products, and distillate oil (#1,#2, and

#4) using the U.S. EPA's TANKS model if these tanks are not connected to an active vapor recovery unit (VRU). If the tanks are connected to a VRU, emissions resulting from their destruction (as a supplemental fuel or in a destruction device) will be reported using the method in 95113(d)(3) if the emissions are not reported as part of the facility flaring reports to the local AQMD/APCD. If they are included in the district flaring emissions report then the appropriate method in 95113(d)(2) would apply - either (A) or (B).

104. Q: Are refineries required to report fugitive emissions of CH_4 and N_2O from wastewater treatment systems dedicated solely to **groundwater remediation**? Note: It seems that groundwater would not meet the definition of wastewater, which is defined as any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.

A: Groundwater does not meet the definition of wastewater and thus refiners are not required to report GHG emissions from groundwater remediation.

105. Q: Are refineries required to report **SF_6 emissions from cogeneration systems**?

A: The facility operator is responsible for reporting SF_6 emissions from electrical equipment that the operator maintains.

106. Q: Do GHG emissions associated with **off-site catalyst regeneration/reclamation** have to be reported by the refinery?

A: No, offsite emissions are not required to be reported.

107. Q: if we report the emissions from our **calciner** at the carbon plant under the voluntary section, do we still need to meet the **quarterly calibration of operator's solid fuel scales** for the pet coke measured at the carbon plant?

A: Emissions for activities that the regulation does not require to be reported may be reported as “optional” in the Reporting Tool. These emissions would not be subject to the quarterly scale calibration requirement.

108. Q: To calculate CO_2 emissions from the **sulfur recovery unit** (SRU), the regulation indicates that you have to measure the flow of acid gas to the SRU. In working with several refineries, I have come across the issue that there are two streams into the SRU: one acid gas stream and one ammonia gas stream. When the regulation refers to "acid gas," does that mean the pure acid gas stream into the unit or the sum of the acid gas and ammonia gas streams? Furthermore, if the regulation only intends for the inclusion of the pure acid gas stream, is the ammonia gas stream accounted for elsewhere or just not included in the inventory?

A: The sour gas that is sent to an SRU contains many compounds, such as CO_2, hydrocarbons, mercaptans and ammonia. To calculate CO_2 emissions from the SRU you will need to consider all gas streams sent to the SRU. If you feel that the default molecular fraction of CO_2 that is provided in the regulation is not appropriate for one or more of the streams entering the SRU, you may elect to use an ARB approved source test plan to better characterize the CO_2 content of a particular flow.

109. Q: There is a refinery with a closed wastewater treatment operation that has no effluent discharge – all of the **water is injected into deep wells**. The required data for wastewater treatment (e.g., COD, sludge removed, N in effluent) are therefore not relevant to GHG emissions for this process, as the only GHG emissions are fugitive component emissions from the equipment. Do those effluent measurements still need to be made?

A: You would not be required to determine wastewater COD, N or any other parameters if the wastewater was injected and there was no surface treatment involved.

110. Q: For **equipment fugitive** emissions at **refineries**, 95113(c)(4)(A) refers to all gas service components, but then 95113(c)(4)(A)(2) requires screening value measurements only for components in natural gas, refinery fuel gas, and PSA off-gas systems. Are all components in gas service included in the monitoring, recordkeeping, and reporting requirements, or just those in natural gas, refinery fuel gas, and PSA off-gas service?

A: The facility is required to extend LDAR screening to all components carrying NG, refinery fuel gas, and PSA off-gas. You should use gas composition data where available to convert from VOC to CH_4.

111. Q: For the **default flare emission** calculation, what exactly does "refinery feed throughput" mean (95113(d)(2)(C))? Is that a dry value? Does this method of calculating emissions account for all GHG emissions from the flare, or would the emissions from fuel combusted as pilot and purge gas need to be accounted for separately?

A: Refinery feed throughput refers to the amount of crude oil processed by the facility. The units are cubic meters of crude per year so you will need to convert from barrels. This method covers only the material delivered to the flare for destruction. Thus emissions from pilot and purge gas would be calculated separately and reported.

112. Q: We do not currently sample the pentane that is used as feedstock to the hydrogen plant but we do measure butane. **We have not yet installed a sampling station** for the times we feed pentane to our hydrogen plant. We do have samples of the vaporized mixture of natural gas, pentane, and butane. But, this vaporized

mixture does not have a flow meter. We do have flow meters that measure the butane, pentane, and natural gas flows before they are vaporized. Are we able to measure the liquid feedstock flows before they are vaporized and take a sample after they are vaporized to get our data for GHG calculations per this regulation?

A: Measurement of the liquid pentane flow rate in units such as liters or gallons per day and conversion to scf/day should be sufficient. Sampling the vapor phase for composition would also be fine here since this is what is actually fed to the hydrogen plant.

113. Q: Regarding **periodic catalyst regeneration** and the data required per the regulation, the guidance document (pg. 10-10) states that the regulation does not specify an analytical methodology or measurement methodology. Does this mean that we have to take samples of the carbon on the spent/regenerated catalyst and analyze in a lab or are we able to calculate the weight percent of the carbon on the catalyst based on the amount of air used during the regeneration?

A: The regulation requires reporters to determine the weight fraction of carbon on both spent and regenerated catalyst. The regulation does not specify a method by which these variables are to be determined. You may use a method to determine these variables of your choosing, subject to verifier review. It is our understanding that actual sampling of the catalysts may be difficult and/or hazardous. You should thoroughly document the method you use (mass balance, etc.) so that its accuracy can be assessed during the verification process.

114. Q: **FCC Coke burn rate calculations** - The K1, K2, and K3 factors stated in the regulation for the calculation for FCC coke burn rate assume a 386 standard factor scf/lb-mole, which is inconsistent with the standard conditions defined in the API Compendium (60°F and 1 atm, Section 3.5 of the Compendium). The standard conditions of the Compendium results in a molar conversion factor of 379.3 scf/lbmole. Our instrumentation uses the 379 standard factor so our K1, K2, and K3 factors are slightly (~2 percent) different. We believe the 379 factor is the appropriate factor for us. Is it acceptable to use the 379 molar conversion factor, which is consistent with our instrumentation?

A: ARB intends to provide an advisory stating that you should use the k-factors appropriate for your standard temperature.

115. Q: If all **carbon going into a hydrogen plant** is accounted for through mass balance, do fugitive emissions need to be quantified separately? The flaring and process vent sections note "...not reported using other methods..."; however, that statement is not present under the fugitive emissions section.

A: Fugitive emissions must be determined separately because the carbon is released as CH_4, not CO_2. Methane has a much greater GWP (21 versus 1) than CO_2. Use the S factor to correct for the carbon fraction reported elsewhere, and then quantify and report this S factor carbon appropriately.

116. Q: The regulation requires **tanks not under vapor recovery** to be included. How does blanketing with natural gas affect the need to report emissions from tanks storing crude oil, gas oil, etc?

A: Unless you recover a portion of your natural gas, you must assume all of it is released to the atmosphere as CH_4, and must be reported.

Compliance, Verification, and Enforcement

117. Q: Is ARB planning to **streamline** GHG reporting to **CCAR and TCR**?

A: ARB staff used the CCAR program as a starting point in developing our mandatory reporting requirements, and the CCAR requirements have since been adjusted to add consistency. As voluntary programs CCAR and TCR programs have somewhat different purposes, with an emphasis on the corporate footprint. For California and other Western Climate Initiative jurisdictions considering GHG reduction strategies, emphasis is on consistency and accuracy for the largest sources that will be the focus of GHG abatement. Fortunately much of the data collected (e.g., fuel use) is applicable to both reporting regimens. In addition ARB and other WCI jurisdictions are working closely with TCR on a system that would allow mass data transfer to a regional emissions database.

118. Q: Are **air districts** able to serve as verification bodies?

A: Yes, air districts may be verifiers if they do not have activities that would constitute a conflict of interest in verifying the emissions data. Accreditation will be required, as it is for verifiers from the private sector. Reporters choose whom they hire as verifiers. For more information about ARB's verification program, please see http://www.arb.ca.gov/cc/reporting/ghg-ver/ghg-ver.htm.

119. Q: Does ARB recognize **CCAR/TCR** accredited verifiers?

A: Only once they are accredited by the ARB as well. They need to take the ARB verifier training program before they are accredited to verify reports submitted under the ARB program.

120. Q: For facilities starting **operation in 2009**, when are reporting and verification required?

A: GHG emissions reporting and verification are required for the first full year of operation. For facilities that did not commence operations by January 2009, the first reports will be due in 2011.

121. Q: What would happen if the verifier **finds a problem**? Will there be a notice of violation issued? How about fines?

A: The verifier will be able to ask the reporter to make any changes to the data and resubmit the information prior to the verification deadline. Almost all mistakes and misstatements will be able to be addressed as informal corrections using the Reporting Tool.

ARB reserves the right to take enforcement action, especially in cases of purposeful misstatements or knowing failure to submit required emissions reports.

122. Q: Will ARB have **special verifiers for cogeneration** facilities?

A: No. Cogeneration cuts across all sectors, and all verifiers need to be qualified to evaluate emissions reports for cogeneration plants. The only sectors that have sector-specific verification requirements are refineries, cement plants, and power entities with electricity transactions.

123. Q: If after reporting my 2008 emissions in 2009 I discover that I **reported something wrong**, either the magnitude of the emissions or the way I set up my facility, what should I do?

A: Contact ARB staff (and your verifier if applicable) to unlock your report so you may make corrections. We encourage all mistakes to be corrected if possible. To help assure independent review when verification is occurring, the verifier and the operator are not provided simultaneous access to the emissions report.

Attachment 1

Examples – Accuracy of Fuel Meters

124. Q: Please give examples of how the availability and **accuracy of fuel meters** determine when an operator needs to install fuel meters, when to report device level fuel consumption, and how to set up emitting activities.

A: If emissions are reported using a fuel-based methodology, emissions must be based on fuel measurements accurate to +/-5 percent. However, if an operator of an electricity generating facility has met this requirement at the facility level, the operator does not necessarily need to achieve the same level of accuracy when reporting sublevel emissions for individual electric generating units. Accuracy requirements do apply when reporting for secondary sectors embedded in larger facilities.

If the operator is able to meet the accuracy requirement when reporting sublevel or secondary sector emissions, then the operator can mark these emitting activities as "summed' and will not need to duplicate reporting at the facility level because the sublevel emissions will also be summed to the facility level in the operator's summary report.

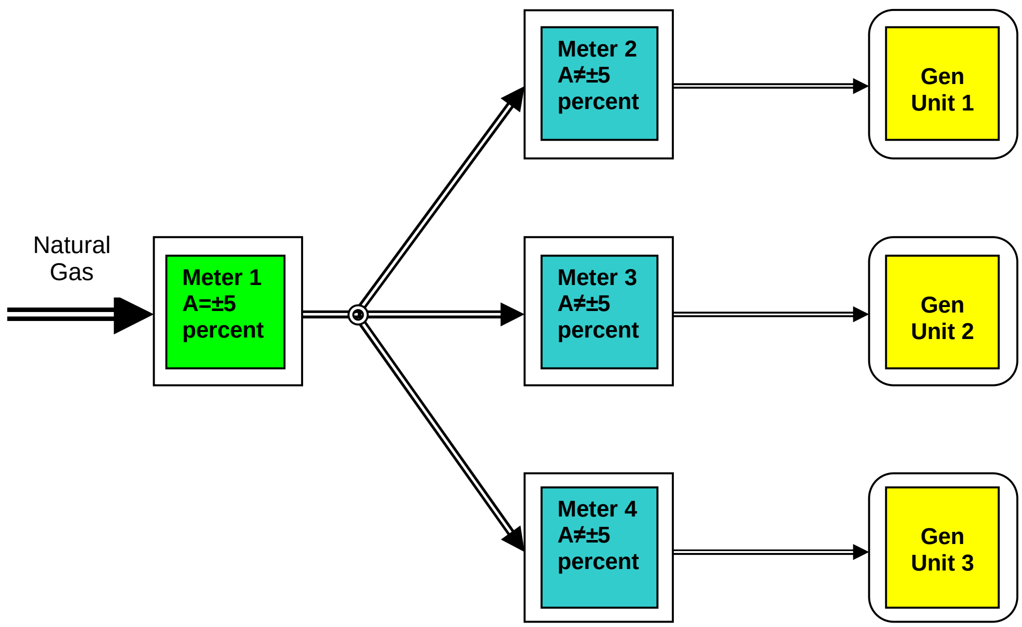
The operator is required to report fuel consumption to the lowest level of metering. If the sublevel reporting of emissions and fuels accounts for the lowest level of fuel metering, there is no need to duplicate reporting by setting up fuel devices at the facility level. If, however, the emitting activities set up by the operator do not reflect the lowest level of metering, then the operator will need to set up devices to report fuel consumption as measured to the last level of metering. Device level reporting of fuel consumption does not need to meet the +/-5 percent accuracy requirement. Here are three examples.

Example 1: An electricity generating facility is not subject to CFR 40 Part 75 and has 3 generating units that are 3 MW each with individual fuel meters. The fuel meters to the generating units are <u>not</u> accurate to +/-5 percent; however, the facility level revenue meter is. The operator plans to use a fuel-based methodology to report emissions. How should the operator report emissions and fuel consumption?

Operators of electricity generating facilities are required to report fuel use and emissions at both the facility level and at the generating unit level if fuel metering is available. In the example, the operator would set up an emitting activity at the facility level that represents emissions based on the revenue meter for all three generating units combined. The operator would report both emissions and fuel consumption for this facility level emitting activity and mark the emitting activity as "summed". This reporting meets the accuracy requirement.

Next, the operator would set up three generating units, each with an emitting activity. The operator reports emissions and fuel consumption for each unit. The emitting activities should be marked "supplemental" to avoid double counting with emissions reported at the facility level. The three unit level emitting activities meet the requirement to report emissions and fuel consumption at the unit level. There is no need to set up additional devices to report fuel usage because the meters to the units are the lowest level of metering.

Figure for Example 1

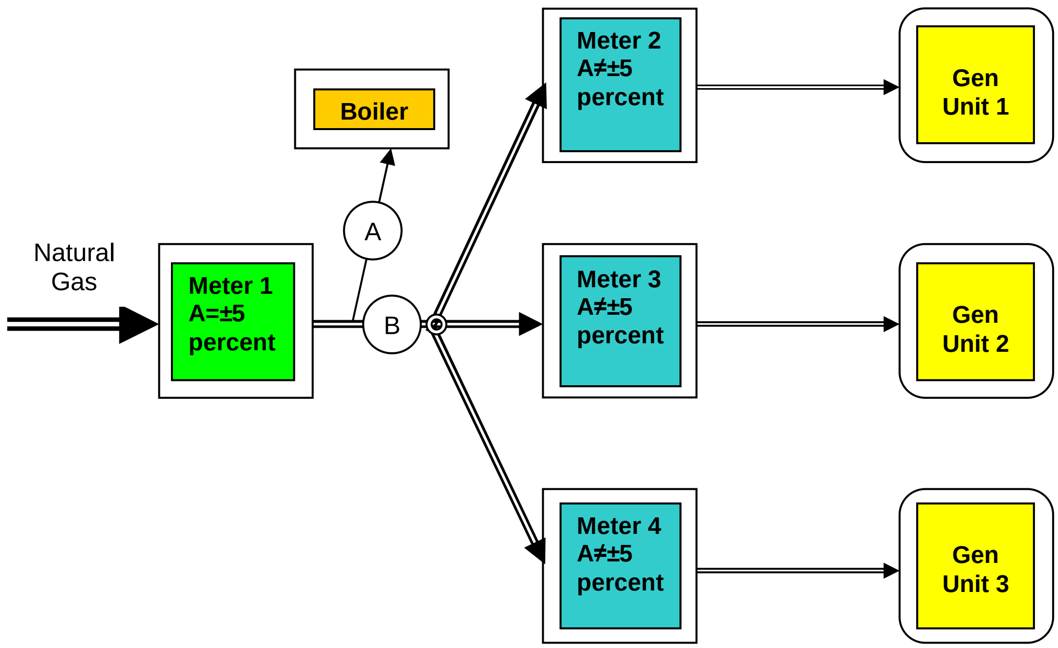


Example 2: An electricity generating facility has 3 generating units (3 MW each) with individual fuel meters and a backup boiler that is not metered. The fuel meters to the generating units are not accurate to +/-5 percent; however, the facility level revenue meter is sufficiently accurate. If the operator wants to use a fuel-based methodology to report emissions, how should the operator report emissions and fuel consumption?

The operator is required to report emissions and fuels associated with electricity generating units separately from other combustion sources on the facility. Because the boiler is not metered and the meters to the generating units are not accurate to +/-5 percent, there is no way to report the generating units separately, unless the emissions from the boiler can be included as *de minimis*. In

that case, separate metering is not required. If the boiler is not *de minimis*, the operator must install a meter(s) to his boiler (see location "A" in the Figure for Example 2) that is accurate to
+/-5 percent, **or** install a meter (or meters) to the generating units (see location "B" in the Figure for example 2) that is accurate to +/-5 percent.

Figure for Example 2



If the operator chooses to install a meter to the boiler, the operator can calculate emissions for the facility using the revenue meter and then subtract emissions calculated for the boiler to determine emissions for the aggregated generating units. In the Reporting Tool the operator should create an emitting activity at the facility level marked "summed" based on the revenue meter. The operator would report emissions and fuel consumption for this emitting activity. Then the operator would set up each generating unit with separate emitting activities and an emitting activity at the facility level for the boiler, marking each of these four emitting activities as "supplemental," and would report emissions and fuel consumption accordingly. There is no need to set up separate fuel meter "devices" because the fuel is already being reported for each generating unit to the lowest level of metering.

Example 3: An electricity generating facility has 3 generating units (3 MW each) with individual fuel meters and a backup boiler that is not metered. The fuel meters to the generating units are not accurate to +/-5 percent; however, the facility level revenue meter is. The operator is subject to CFR 40 Part 75 and has CEMS on each of his generating units. The operator intends to report CO_2 using the CEMS data. How should the operator report emissions and fuel consumption?

Even though the operator will be using CEMS data to report CO_2 emissions for the units, the operator is still required to report fuel consumption and will need to use a fuel-based methodology to report N_2O and CH_4 for all sources and CO_2 for the boiler.

Step 1. Reporting N_2O, CH_4, and fuels at the facility level.
The operator should set up an emitting activity at the facility level based on the revenue meter and marks it "summed." This emitting activity includes all emission sources, including the boiler. The operator uses this emitting activity to report N_2O and CH_4 and fuel consumption for all sources combined.

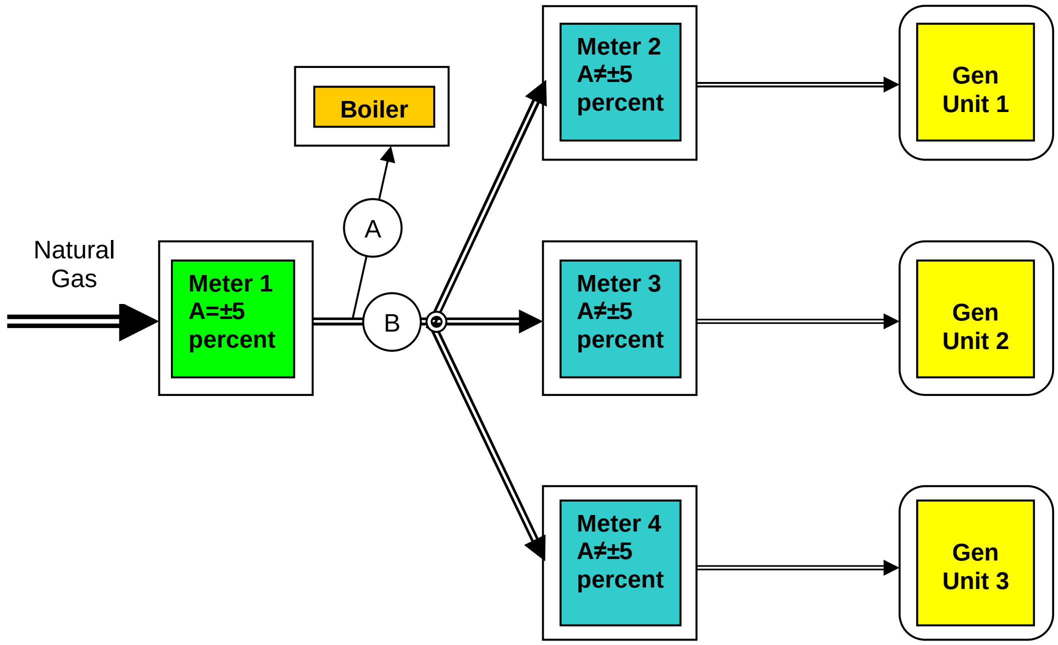
Step 2. Reporting N_2O, CH_4, and fuels at the unit level.
The operator creates generating units in the Reporting Tool for each unit and sets up an emitting activity under each unit marked "supplemental." The operator reports N_2O and CH_4 emissions and fuels for each unit.

Step 3. Reporting CO_2 at the unit level.
The operator sets up a second emitting activity under each unit marked "summed." The operator reports CO_2 emissions subject to CFR 40 Part 75. There is no need to associate a fuel type with this emitting activity. The operator will use "remaining emissions" when reporting CO_2.

Step 4. Reporting CO_2 for the boiler.
The operator sets up an emitting activity at the facility level for the boiler marked "summed." The CO_2 emissions for the boiler is pre-calculated by subtracting the sum of all CEMS-based CO_2 emissions from the generating units from the total CO_2 emissions calculated for the whole facility using a fuel-based method and the revenue meter. There is no need to associate a fuel type with this emitting activity. The operator will select "remaining emissions" when reporting CO_2 emissions for the boiler.

The operator has met the requirement to report CO_2 at the facility level by marking the sublevel reporting as "summed" to the facility level. Furthermore, all emissions were reported in a manner that meets the accuracy requirements of the regulation. There is no need to set up additional devices because the operator has already reported fuel consumption to the lowest level of metering when he/she reported for each generating unit.

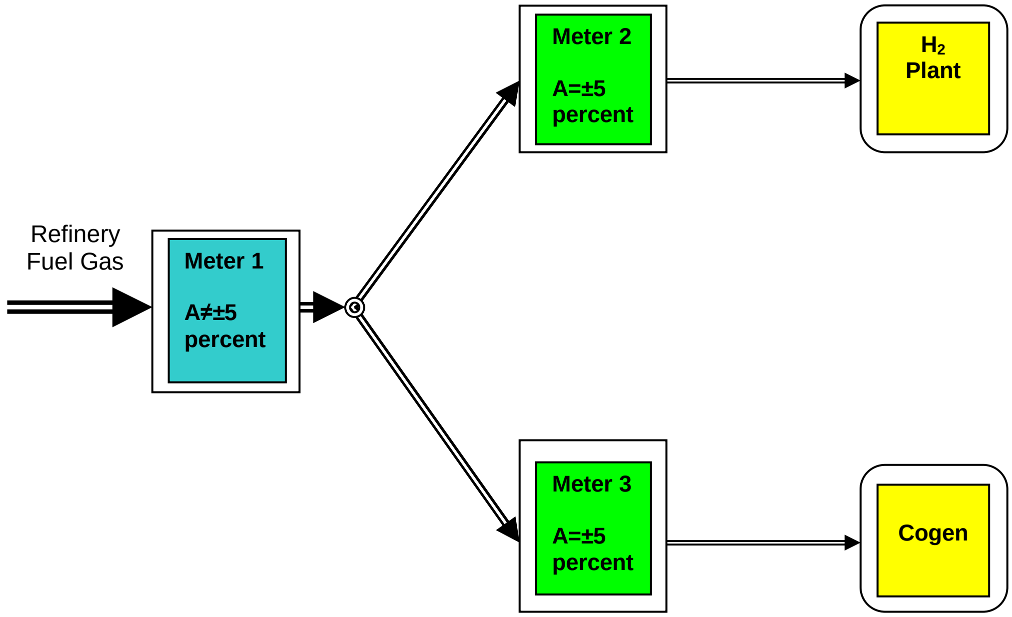
Figure for Example 3 <u>where subject to CFR Part 75</u>



Example 4: An oil refinery has a fuel meter that feeds a hydrogen plant and a cogeneration system on-site. The meter is NOT accurate to +/-5 percent. How should the operator report emissions and fuel consumption for the cogeneration system and the hydrogen plant?

The operator is required to address the discrete requirements of the regulation by estimating GHG emissions for the hydrogen plant and the cogeneration system under common operational control, separately from other refinery operations. To meet these requirements the operator must install meters that are accurate to +/-5 percent for both the hydrogen plant and the cogeneration system. An exception would be if either source is *de minimis*. For *de minimis* sources of emissions the operator may use a simplified methodology to calculate emissions without installing a meter.

Figure for Example 4



Example 4: Stationary combustion emissions from a hydrogen plant and cogeneration system must be calculated separately. Therefore, Meters 2 and 3 must meet the +/-5 percent accuracy requirement because data for these meters are used to calculate GHG emissions for the cogeneration facility and hydrogen plant. In this example, meter 1 is not required to meet the +/-5 percent accuracy requirement.

(Last page)