CHAPTER 12: GENERAL STATIONARY COMBUSTION FACILITIES
(Guidance for Regulation Section 95115)

Operators of General Stationary Combustion facilities (or GSCs) are required to report their GHG emissions as specified in section 95115 of the reporting regulation, in addition to following the general requirements in sections 95103 to 95105. This chapter will help to identify whether a facility is classified as GSC, and what is needed to meet the GHG reporting requirements. We provide examples and other guidance to assist with the process. In addition, in January 2009 ARB will provide an on-line GHG reporting tool to guide operators through the reporting process and help to ensure that reported data are accurate and complete. The main page for GHG emissions reporting, with guidance documents, access to the tool, and other information, is located here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

The emissions estimation requirements for General Stationary Combustion facilities are different from the other industrial sectors required to report. This guidance focuses specifically on those portions of the regulation relevant to estimating emissions from GSCs. It is also important to refer to other portions of this document, particularly chapters 2 to 6, for guidance on requirements applicable to all facilities and sectors. In some situations, such as for facility cogeneration activities or electricity purchases, it will be necessary to refer to the chapters that provide details for meeting those requirements.

12.1 Defining a General Stationary Combustion (GSC) Facility

Under the GHG reporting regulation, GSCs (or General Stationary Combustion sources) are facilities that emit greater than or equal to 25,000 metric tonnes (MT) of CO_2 annually from on-facility stationary combustion sources, and are not already included in the sectors specifically identified for reporting (such as petroleum refineries or power generation). These GSC facilities do not belong to any single industrial sector, but share a common element of being large sources of GHG emissions resulting from stationary combustion. In evaluating whether the facility emits 25,000 MT or more of CO_2 per year, count all stationary combustion sources, but do not include any direct process emissions (such as from chemical reactions), fugitive, or mobile or portable equipment emissions. Also, do not include in the assessment any indirect CO_2 emissions associated with purchased electricity or purchased thermal energy.

Evaluating the 25,000 Metric Tonne CO_2 Threshold

Applies to Single Facility

Include:
All stationary combustion sources, including any biomass or biogas combustion

Do Not Include:
Fugitive emissions
Process emissions
Mobile sources

The purpose of this chapter is to provide guidance on the requirements of section 95115 of the mandatory GHG reporting regulation. As described more specifically in Chapter 1 of this document, this guidance does not add to, substitute for, or amend the regulatory requirements as written in these or other sections of the regulation [Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations].

The 25,000 MT CO_2 threshold is a facility-wide threshold. For example, if a single owner operates three processing plants, and the processing plants are distinct, geographically separate facilities, each plant would be evaluated separately to determine whether the 25,000 MT threshold is exceeded for each plant. If one of the plants exceeds the threshold and the other two do not, only the plant emitting more than 25,000 MT per year would be subject to the reporting regulation (assuming none of the plants are included in any of the other reporting sectors).

12.1.1 GSC Facility Determination

ARB staff is notifying all facilities that may be subject to reporting. Whether or not you receive a direct notification, we recommend that you perform a quick emissions assessment based on fuel use to evaluate whether your facility may fall under the reporting requirements.

Records of annual facility fuel use and the fuel-to-emissions look-up table below can provide a simple method for approximating gross GHG emissions. In performing this screening assessment, it is important to include all fuel used by all stationary combustion sources under common operational control within the facility boundary. Include any on-site power generation or cogeneration, biomass or biogas combustion from stationary sources, and space heating.

Table 12.1.1 provides fuel usage and emissions factors to estimate CO_2 emissions for some common fuel types. This table alone does not determine reporting applicability, but can be used as a quick screening tool. In performing the assessment, exclude fuel used for vehicles or other sources not considered "stationary combustion." If using fuel use records for a year prior to 2008 (or prior to a later year for which you are assessing applicability), consider also any expected growth in fuel use between the year of your records and the year for which reporting is being considered. If after performing this first assessment, facility emissions are substantially below the threshold based on fuel use, and you do not expect significant growth in fuel use, it is probably safe to assume the facility is not subject to reporting.

However, if based on overall facility fuel usage it appears that the emissions are reasonably close to the threshold, a more complete screening is highly recommended. This can be done using the emission factors provided in Appendix A (Table 4) of the regulation to

Example 1. Evaluating CO_2 Emissions

ACME Rockets has 4 pieces of stationary equipment: three boilers and an onsite cogeneration unit with over 1 MW generating capacity producing over 2,500 tonnes CO_2/year.

The boilers burned 411,830 MMBtu of natural gas with a heat content of 1060 Btu/Scf. This produces 22,000 metric tonnes CO_2.
(Using an emission factor of 53.42 kg CO_2/MMBtu, provided in the regulation)

The cogen unit burned 93,597 MMBtu of natural gas. This produces produce 5,000 metric tonnes of CO_2. (Using same emission factor above)

Total CO_2 from stationary combustion:
Boilers + Cogen = 22,000 + 5,000 = 27,000 metric tonnes of CO_2

The facility emissions exceed the 25,000 metric tonne CO_2 reporting threshold and so must submit a GHG emissions data report to the ARB.

calculate CO_2 emissions for each fuel type at the facility used in stationary combustion sources. The stationary emissions for each fuel type are summed for all of the fuels used to determine a facility wide CO_2 emission number to evaluate against the 25,000 tonne threshold. Example 1 provides a sample calculation.

Table 12.1.1 Approximate Fuel Combustion Quantities to Produce 25,000 Tonnes of CO_2

Fuel Type	*Fuel Units*	*Emission Factor Kg CO_2/Unit*	*Amount of fuel to produce 25,000 MT CO_2*	*Amount of fuel to produce 2,500 MT CO_2*
Natural Gas (unspecified)	scf	0.05	459,140,464	45,914,046
	MMBtu	53.02	471,520	47,152
LPG (energy use)	Gal	5.79	4,317,757	431,776
Distillate Fuel (#1,2 &4)	Gal	10.14	2,466,011	246,601
Motor Gasoline	Gal	8.80	2,841,174	284,117
Landfill Gas	MMBtu	52.03	480,503	48,050
	scf	0.025*	916,301,950	91,630,195
Coal (unspecified other industrial)	Short Ton	2,082.89	12,003	1,200
Jet Fuel	Gal	9.56	2,614,682	261,468
Kerosene	Gal	9.75	2,562,972	256,297
Petroleum Coke	MMBtu	102.04	244,996	24,500
	Short Ton	2530.70	9,879	988
Crude Oil	Gal	10.29	2,430,348	243,035

*Note: The emission factor shown includes only the CO_2 emissions from the combustion of landfill gas. It does not include the CO_2 pass-through emissions, which are not counted for applicability purposes.

12.1.2 Facility with Combustion Sources Including Cogeneration or Electricity Generation

If the facility has general combustion sources, such as boilers, as well as electricity generation or cogeneration units, reporting requirements will vary depending on the level of overall facility emissions and whether additional requirements for cogeneration or electricity generation are triggered. Where the facility's cogeneration or electricity generating system is rated $\geq$1MW and emitted $\geq$2,500 metric tonnes CO_2 in the report year,[1] additional reporting requirements apply.

Figure 12.1 below shows several possible facility scenarios and the reporting requirements for each. In this example, we use a facility with large boilers and a cogeneration system. Boilers are only provided as an example, and any combination of stationary combustion sources present at the facility would be used to determine reporting thresholds.

In assessing the applicability of reporting requirements to cogeneration facilities, only the emissions from electricity generating activities need be counted. The operator can refer to regulation section 95112 (see Chapter 9 of this document) to review the

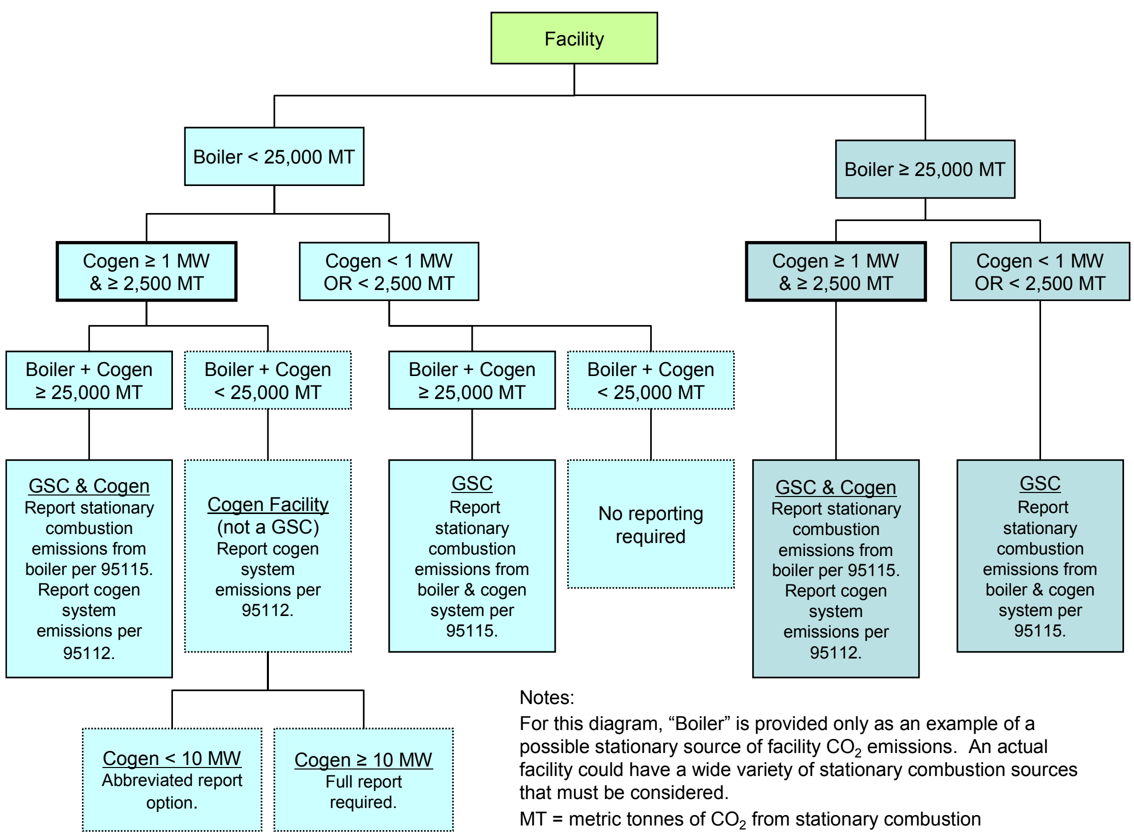
[1] The "report year" is the calendar year for which emissions are being reported.

method for separating electricity generating emissions from other emissions, if there is a question of whether a cogeneration facility is of sufficient size to emit 2,500 metric tonnes CO_2 from electricity generation only. This is not necessary if the operator wants to report even if the electricity portion of emissions is below the threshold.

A key difference among the scenarios in Figure 12.1 is that, in cases where electricity emissions are under 2,500 MT CO_2 at plants <1 MW, the cogeneration emissions can be calculated using only fuel consumption, and combined with the reporting of general fuel combustion emissions. For facility configurations with cogeneration operations that exceed these thresholds, the full cogeneration emission estimation method must be used, as described in Chapter 9 and section 95112 of the regulation.

If the facility has electricity generation without cogeneration on-site, determining whether the generating facility reporting requirements apply uses the same logic and flow shown in Figure 12.1. Just replace "cogeneration" with "electricity generation," and follow the requirements of section 95111 if needed. Electricity generating facility requirements are discussed in Chapter 8 of this document, while cogeneration is discussed in Chapter 9.

Figure 12.1. Stationary Combustion and Cogeneration Reporting Applicability



12.2 GSC Reporting Requirements

This section explains the information that GSC facility operators must include in their GHG emissions data report. As mentioned previously, this section focuses on the key GHG reporting requirements in the regulation for GSCs, but it is also important to be familiar and review the general requirements too.

We will discuss estimating and reporting the following items:

- Fuel consumption, by fuel type for the entire facility
  - and fuel consumption for individual process units or groups of units where separately metered
- GHG emissions, by gas type (i.e., CO_2, N_2O, CH_4) for the entire facility
  - and GHG emissions produced for each fuel type used
- Reporting emissions from electricity generating units or cogeneration units
- Reporting indirect energy usage

12.2.1 Estimating Fuel Consumption

As with all sectors, GSC facilities need to report fuel consumption by fuel type for the overall facility for those sources subject to reporting. In the case of GSCs, this would mean all fuel consumed by stationary combustion sources at the facility. Emissions from portable or mobile equipment are not included in these estimates. Generally overall facility fuel use information can be readily obtained from natural gas or other fuel billing data. This data, totaled for the entire year, will generally be sufficient for reporting the overall facility fuel usage (section 95115(a)(2)). Remember that the consumption of each fuel type must be separately identified and reported

Fuel use must be reported for individual process units. Reporting of GHG emissions at the process unit level is not required.

For fuels that are stored on-site, the "stock method" may be an appropriate method for estimating total facility fuel use. The equation for this calculation is provided in the regulation (section 95115(a)(2)(A)), and it provides an estimate of the amount of fuel consumed by the facility. The equation is:

Fuel Consumption in the Report Year =
(Total Fuel Purchases – Total Fuel Sales)
+ (Amount Stored at Beginning of Year – Amount Stored at End of Year)

The regulation also requires the reporting of annual fuel consumption for each process unit, or group of units, where fuel use is separately metered (section 95103(a)(2)). Therefore it is important to keep records of annual fuel use for those devices (or groups of devices), processes, or activities that are served by separate fuel meters. These "units" will be individually reported using the ARB's GHG reporting tool. Examples of individual process units are boilers, dryers, heaters, cogeneration systems, electricity generation, and other stationary combustion sources. If three boilers are fed through a single meter, then the combined fuel use for the three boilers may be reported as a single value.

Note that it is possible that the summed fuel usage for the individual boilers, devices, or other units, will not add up to the overall reported facility fuel use. This is possible because not all fuel consumed at the full facility will necessary be routed through subordinate meters that completely capture all fuel use. We understand this may occur, but we are requiring that the device or unit fuel use be separately reported to better track and understand the individual sources of GHG emissions.

When providing fuel consumption information, all reported fuel values need to be converted to the appropriate units listed below:

- million standard cubic feet for gases,
- gallons for liquids,
- short tons for non-biomass solids, and
- bone dry short tons for biomass-derived solid fuels.

Conversion factors are provided in Table 1 in Appendix A of the regulation for converting between the different units of measure.

12.2.2 Estimating CO_2 Emissions

When reporting CO_2 emissions, emissions need to be calculated and reported at two levels of detail. Reporting of overall facility CO_2 emissions from stationary combustion is required. This total will include two components: fossil fuel emissions, and any biomass combustion emissions, which are separately reported. In addition, for each fuel used at the facility, the regulation requires reporting of CO_2 emissions for each individual fuel type for combustion sources subject to reporting.

So, for example, if the facility has a boiler that burns natural gas and produces 20,000 metric tonnes of CO_2 per year, an oil-fired heater that produces 5,000 tonnes of CO_2 per year, and a cogeneration facility burning pure biomass that produces 10,000 metric tonnes of CO_2 per year, the following would be reported:

Total Facility Fossil CO_2 Emissions	25,000 tonnes/year
Total Facility Biomass CO_2 Emissions	10,000 tonnes/year
Natural Gas CO_2 Emissions	20,000 tonnes/year
Fuel Oil CO_2 Emissions	5,000 tonnes/year
Biomass CO_2 Emissions	10,000 tonnes/year

In this simplified example the sum of the fossil fuel CO_2 from the individual combustion sources adds up to the total facility emissions. In a real-world situation this may not always be the case, depending on differences in how overall facility fuel use is accounted for versus how the individual fuels are measured. In reporting, it is important that any biomass combustion be separately identified and reported because these emissions can be considered "carbon-neutral" and could be treated differently in future evaluations of overall facility emissions. However, biomass

Biomass combustion emissions are included when determining whether the 25,000 tonne CO_2 threshold is exceeded.

combustion emissions are included in determining if the 25,000 tonne CO_2 threshold is exceeded.[2]

12.2.2.1 GSC Facilities (not in crude oil or natural gas production sectors)

The GSC sector includes a subgroup of facilities producing crude oil or natural gas, identified by NAICS code 211111. For facilities not involved in oil or gas production, facility operators have several options for computing the facility and fuel CO_2 emissions, which include the following:

- *Default Emission Factors*: In general this is the most straightforward approach for estimating facility emissions. Table 4 in Appendix A of the regulation provides emission factors for the most common types of fuels used in stationary combustion. Method 95125(a) in the regulation provides the equation for applying those emission factors and calculating emissions.
- *Continuous Emissions Monitoring System (CEMS) devices*: CEMS continuously monitor and record the CO_2 emissions from an exhaust stack at a facility. If present, CEMS may be used to estimate CO_2 emissions from units subject to reporting if the system meets the specifications in section 95125(g) of the regulation.
- *Measured Heat Content*: Instead of using the default emission factors with a default heat content value, it is also possible to use a fuel specific heat content value measured for the fuel used at the facility. Section 95125(c) in the regulation describes this option in detail. If this method is used, it is also necessary to report the annual average heat content of the fuel in the emissions. This method is more complex and costly than using the default emission factors, but it could provide GHG estimates that are more specific to the actual fuel used at the facility.

> **Measuring heat or carbon content**. The option to use measured heat or carbon content is allowed for fuels even if the ARB tables provide a default high heat value for the fuel. However, the more stringent requirements of section 95125(c) and (d), which specify sampling methodologies and frequencies, must be used.
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> **Waste and biomass options.** For CO_2 emissions from combustion of biomass, MSW, or waste derived fuels with biomass, the option to use the more stringent methods provided 95125(h) is allowed even if the ARB tables provide a default high heat value for the fuel.

- *Measured Carbon Content*: Another option is to test for the carbon content of the fuels. Method 95125(d) in the regulation describes this option in detail. If this method is used, the annual average carbon content of the fuel must also be reported. Like the heat content approach, this method requires more resources than using default emission factors.

[2] There is one exception to this. For landfill gas or biogas fuels, the pass-through CO_2 emissions, assumed to be 50% of the gas, is not included in the 25,000 tonne emissions evaluation for applicability. However the complete emissions, including the pass-through CO_2 must be reported.

- *Source Testing*: For CO_2 emissions at GSC facilities, source testing may be performed for biomass or waste-derived fuels if a default high heat value is not supplied in Appendix A of the regulation. See regulation sections 95115(b)(2), and 95125(h) as discussed in Chapter 13. Also see additional guidance in Appendix B of this document.

If using an alternative fuel such as such as municipal solid waste, tires, or waste oil, refer to Table 5 in Appendix A. This table provides emission factors in terms of kg CO_2/MMBtu. For the fuel type, look up the heat content (provided as MMBtu/unit consumed) in Table 4 of Appendix A. This heat content value can then be used with Table 5 and the amount of fuel used to compute the emissions from the fuel burned. If Table 4 does not have a heat content value for the fuel type, then heat content or carbon content testing will be necessary (section 95115(b)(2)(C)). Also, source testing is an option for a limited set of fuels as specified in section 95125(h).

Biomass and fossil fuel combustion components must be separately quantified and reported. This can be performed through separate calculation by fuel type or through other techniques. If co-firing waste-derived fuels that include biomass, it may be beneficial for the operator to perform analysis to quantify the potentially carbon-neutral biomass portion of the CO_2 produced as specified in section 95125(h)(2). If the methods in section 95125(h)(2) are not used, another approach must be developed to identify and report the biomass emissions separately.

Example 2 describes how to calculate CO_2 emissions from stationary combustion. The example uses a default emission factor and default heat content for natural gas as provided in Appendix A.

A very **common error** that can occur in these types of calculations is not converting the resulting kg of CO_2 to metric tonnes. Most of the equations in Section 95125 include a conversion factor for kg to metric tonnes. However, it is important to always double check their calculations for all required unit conversions. Also, the default emission factors are provided in specific units. Be sure that that the fuel consumption units are the same as the default emission factor fuel units used for the calculation.

If any of the facility stationary equipment is for electricity generation or cogeneration, then the emissions calculations methods prescribed for the power generation and cogeneration sectors must be used for calculating and reporting those emissions sources. See Chapter 8 for electricity generation and Chapter 9 for cogeneration.

As with all sectors, reporting of mobile sources of emissions is optional. The reporting tool will also allow voluntarily reporting of information from other sources not required to be reported. Any of these sources voluntarily reported will be subject to verification. During reporting these data sources will be tagged as voluntary. For the total facility emissions summary, voluntary emissions will be listed separately from the emissions from mandatory sources specified in the regulation.

12.2.2.2 GSC Facilities (crude oil or natural gas production)

The previous examples are for facilities not involved in crude oil or natural gas production. Because oil and gas production facilities tend to have less consistent fuels, different emission estimation methods are required to adequately quantify the CO_2 emissions. For these facilities, identified with a NAICS code of 211111, the following options are provided for estimating the facility CO_2 combustion emissions.

- For natural gas and associated gas combustion, use the methods specified in section 95125(c) or 95125(d). These methods require the measurement of the heat or carbon content of the fuel to characterize the fuel more accurately than would be obtained using default emission factors and heat values. Details regarding the use of these methods are provided in Chapter 13.

- For the combustion and/or destruction of low Btu gases, the methods specified in section 95113(d)(3) or section 95125(f), as applicable, must be followed. These methods require either the measurement of the fuel carbon content, heat value, heat and carbon, or the use of continuous emissions monitoring systems (CEMS) to compute the CO_2 emissions. Refer to the appropriate sections of the guidance document for additional information on the application of these methods.

- For the combustion of fuel mixtures, the methods specified in section 95125(f) need to be used to compute facility CO_2 emissions. Depending on the fuel type and if mixtures are burned or not, a variety of approaches for estimating the emissions are provided.

> **Unit Conversions:**
>
> A very **common error** that can occur is not converting the kilograms (kg) of CO_2 to metric tonnes. Most of the equations in Section 95125 include a conversion factor for kg to metric tonnes. However, reporters should always carefully check your calculations for all required unit conversions. This needs special attention when using the provided emission factors to ensure that the fuel use input is the same in the same units as the emission factors.

12.3 Calculating CH_4 and N_2O Emissions

All GSCs need to calculate and report their N_2O (nitrous oxide) and CH_4 (methane) emissions from stationary combustion sources at the facility. The following options are available to GSCs when calculating their N_2O and CH_4 emissions:

- Default Emission Factors: Table 6 in Appendix A of the regulation provides N_2O and CH_4 emission factors for the most common types of fuels used in stationary combustion. Method 95125(b) in the regulation provides the equation for applying these emission factors and calculating emissions. Either the default heat content can be used, if provided in Appendix A, or a measured value can be applied (see section 95125(c) for methods). If the heat content is measured for any combusted fuel, it must also be reported (section 95110(a)(3)(C)).
- Optionally, source testing may be performed to develop facility-specific emission factors for N_2O or CH_4. Section 95125(b)(4) describes the mechanism

for developing facility-specific source test data to determine the N_2O or CH_4 emissions from fuel combustion.

The following example uses the information from Example 2 and calculates the N_2O and CH_4 emissions from the facility natural gas combustion.

As with CO_2 emissions, the facility N_2O and CH_4 emissions are required to be reported as a total value for the entire facility, as well as subdivided by each fuel type combusted (section 95103(a)(2)).

Example 2: N_2O and CH_4 emissions from Natural Gas Combustion

Situation:
500 MMScf of Natural Gas are burned per year at the facility

Question: How much N_2O and CH_4 does this produce?

Default heat content: 1,027 Btu/scf {From fuel supplier
Default N_2O emission factor: 0.1g/ MMBtu {Values from Table 6 of regulation
Default CH_4 emission factor: 0.9 g/MMBtu

Equation from regulation Method 95125(b)(3):

$$CH_4 \text{ or } N_2O = \text{Fuel} * HHV_D * EF * 0.001$$

Step 1: Ensure all inputs are in the same units. The default emission factors are provided in *g*/MMBtu and not kg/MMBtu

Convert the default emission factors from g/MMBtu to kg/MMBtu:

N_2O: 0.1 g/MMBtu * 0.001 kg/g MMBtu = 0.0001 kg/ MMBtu
CH_4: 0.9 g/MMBtu * 0.001 kg/g MMBtu = 0.0009 kg/MMBtu

Step 2: Apply the equation:

N_2O = 500,000,000 scf * 0.001027 MMBtu/scf * 0.0001 kg/MMBtu *0.001 metric tonne/kg

CH_4 = 500,000,000 scf * 0.001027 MMBtu/scf * 0.0009 kg CH4/MMBtu *0.001 metric tonne/kg

N_2O = 0.05 metric tonne
CH_4 = 0.46 metric tonne

Repeat this process for any other fuels burned

12.4 Estimating Electricity Generation or Cogeneration Emissions

If electricity generation or cogeneration occurs at the facility (within the same contiguous boundary and under the same operational control), emissions from these activities must be included in the emissions data report. If the electricity generating or cogeneration facility has a nameplate generating capacity of 1 MW or more, and its CO_2 emissions from electricity generating activities trigger the separate reporting threshold of 2,500 or more metric tonnes, the report must comply with the requirements of regulation sections 95111 and 95112, as applicable. Figure 12.1 may assist you in evaluating which reporting requirements apply. Regulation section 95111 includes the electricity generating facility reporting requirements and is described in Chapter 8 of this document, while section 95112 provides the cogeneration system requirements and is covered in Chapter 9. Refer to those sections of the regulation and the associated guidance chapters for more information.

> *Do you have electricity generation or a cogeneration system on site?*
>
> If your system is at least 1 MW and emitted at least 2.500 MT CO_2 from electricity generation, refer to the methods provided for the electricity generation and cogeneration sectors to calculate GHG emissions from these sources. See Chapters 8 and 9.

If your electricity generating activities are not large enough to trigger these additional reporting requirements, include these emissions in your facility GHG report as additional stationary sources, with emissions calculated specific to fuel type like your other sources.

The regulation also includes definitions for “cogeneration facility,” “cogeneration system,” “generating facility,” “generating unit,” and “electricity generating facility,” which may be helpful in evaluating whether these types of activities or units are at the facility.

12.5 Estimating Indirect Energy Use

The regulation also requires GSC facilities to report their indirect energy use. Indirect energy is energy purchased from another source such as electricity or heat. Only the energy use needs to reported, not the associated emissions. Electrical energy is reported as kilowatt-hours (kWh) and thermal energy is reported as British thermal units (Btu). The guidance for regulation section 95125(k), found in Chapter 13, provides additional information about how to report energy use.