## Greenhouse Gas Inventory Guidance

# Direct Emissions from Stationary Combustion Sources

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The U.S. EPA Center for Corporate Climate Leadership's (The Center) Greenhouse Gas guidance is based on The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (GHG Protocol) developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). The Center's GHG guidance is meant to extend upon the GHG Protocol to align more closely with EPA-specific GHG calculation methodologies and emission factors, and to support the Center's GHG management tools.

For more information regarding the Center for Corporate Climate Leadership, visit www.epa.gov/climateleadership.

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# Section 1: Introduction

Combustion of fuels in stationary (non-transport) combustion sources results in the following greenhouse gas (GHG) emissions: carbon dioxide ($CO_2$), methane ($CH_4$), and nitrous oxide ($N_2O$). Sources of emissions from stationary combustion include boilers, heaters, furnaces, kilns, ovens, flares, thermal oxidizers, dryers, and any other equipment or machinery that combusts carbon bearing fuels or waste stream materials.

This document presents guidance for calculating scope 1 direct GHG emissions resulting from stationary combustion of fuels at owned/operated sources. This guidance applies to all organizations whose operations involve stationary combustion of fuel.

## 1.1 Greenhouse Gases Included

The greenhouse gases $CO_2$, $CH_4$, and $N_2O$ are emitted during the combustion of fuels. $CO_2$ accounts for the majority of the GHG emissions from stationary combustion sources. In the U.S., $CO_2$ emissions represent more than 99 percent of the total $CO_2$-equivalent GHG emissions from all commercial, industrial, and electricity generation combustion sources. $CH_4$ and $N_2O$ emissions together represent less than one percent of the total $CO_2$-equivalent emissions from the same sources.[1]

Organizations should account for all $CO_2$, $CH_4$, and $N_2O$ emissions associated with stationary combustion. Given the relative emissions contributions of each gas, $CH_4$ and $N_2O$ emissions are sometimes excluded by assuming that they are not material. However, as outlined in Chapter 1 of the GHG Protocol, the materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources and categories of GHGs, and included in an organization's GHG inventory.

Emissions of $CH_4$ and $N_2O$ depend not only upon fuel characteristics, but also on technology type and combustion characteristics, application of pollution control equipment, and ambient environmental conditions. Emissions of these gases also vary with the size, efficiency, and vintage of the combustion technology, as well as maintenance and operational practices. However, the methods used to calculate $CO_2$ emissions can also be used to calculate emissions of $CH_4$ and $N_2O$ with reasonable accuracy when applying appropriate $CH_4$ and $N_2O$ emission factors.

For organizations that wish to examine $CH_4$ and $N_2O$ emissions from stationary combustion sources in more detail, a list of references for calculating these emissions is included in Appendix A.

## 1.2 Biomass Fuels

Not all stationary combustion sources burn fossil fuels. Biomass (non-fossil) fuels (e.g., forestry-derived, agriculture-derived, biomass-derived gases) may be combusted in stationary sources independently or co-fired with fossil fuels. The emission calculation methods discussed in this document can be used to calculate $CO_2$, $CH_4$, and $N_2O$ emissions from combustion of these fuels. The GHG Protocol requires that $CO_2$ emissions from biomass combustion at stationary sources are reported as biomass $CO_2$ emissions (in terms of total amount of biogenic $CO_2$ emitted) and are tracked **separately** from fossil $CO_2$ emissions. Biomass $CO_2$ emissions are not included in the overall $CO_2$-equivalent emissions inventory for

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[1] See Table 3-7 of U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018, EPA 430-R-20-002, April 2020.

organizations following this guidance. $CH_4$ and $N_2O$ emissions from biomass are included in the overall $CO_2$-equivalent emissions inventory. There has been increased scientific inquiry into accounting for biomass in energy production. The EPA's Science Advisory Board found that "there are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality may not an appropriate assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably."[2] According to the GHG Protocol Corporate Standard, "consensus methods have yet to be developed under the GHG Protocol Corporate Standard for accounting of sequestered atmospheric carbon as it moves through the value chain of biomass-based industries," though some general considerations for accounting for sequestered atmospheric carbon are discussed in Chapter 9 and Appendix B of the GHG Protocol Corporate Standard.

If an organization purchases biogas that is delivered through a shared natural gas pipeline, see Appendix A of the GHG Protocol Scope 2 Guidance for a discussion of appropriate GHG accounting for this situation.

## 1.3 Waste-Derived Fuels

Waste-derived fuels in solid, liquid, and gaseous form may be combusted in stationary sources as well. Typical waste derived fuels include, but are not limited to, used tires, used motor oils, municipal solid waste (MSW), hazardous waste, landfill gas, and by-product gases. These waste-derived fuels are treated like any other fuels in an organization's inventory. Therefore, any GHG produced from combustion of a fossil-based waste product is reported in an organization's inventory. Any $CO_2$ emissions from combustion of a biomass waste are treated as biomass $CO_2$ as described in Section 1.2. This applies to entire waste streams or portions of the waste stream. For example, the $CO_2$ produced from combusting the biomass portion of MSW (e.g., yard waste, paper products) is reported as biomass $CO_2$. The $CO_2$ produced from combusting the fossil portion of the MSW (e.g., plastics) is reported as $CO_2$ and is included in an organization's inventory.

Emissions from waste-derived fuels only include the actual emissions from the combustion process and do not include any "offsets" from use of the waste-derived fuel.

## 1.4 Non-Combustion Emission Sources

The combustion of fuel does not account for all GHG emissions related to stationary combustion sources. For example, use of natural gas may result in fugitive methane emissions from leaking gas transportation lines owned by the organization. Storage of fuels may also result in fugitive emissions. For example, methane is emitted from fuel storage tanks or from coal piles. Typically, these sources are minor compared to combustion emissions, however, organizations should account for these non-combustion sources using guidance specific to the fugitive emissions from their sector.

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[2] EPA Science Advisory Board Review of the 2011 Draft Accounting Framework for CO2 Emissions for Biogenic Sources Study. 2012. https://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument.

# Section 2: Calculating Emissions

There are two main methods for estimating GHG emissions from stationary combustion sources:

- Direct measurement
- Analysis of fuel input

Direct measurement of $CO_2$ emissions is performed through the use of a Continuous Emissions Monitoring System (CEMS). Fuel analysis is essentially a mass balance approach in which carbon content factors are applied to fuel input to determine emissions. Both methods are described in more detail in the following sections.

For both the CEMS and fuel analysis approaches, it is recommended that organizations calculate emissions by facility as opposed to aggregated entity-wide emissions only. This method increases the accuracy and credibility of the inventory.

## 2.1 Continuous Emissions Monitoring System (CEMS) Method

Continuous emissions monitoring is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. Several U.S. EPA regulatory programs (e.g., Acid Rain Program, New Source Performance Standards, Greenhouse Gas Reporting Program [GHGRP], and Maximum Available Control Technology Standards) have provisions regarding CEMS.

CEMS can be used to measure $CO_2$ emissions. Title IV of the U.S. Clean Air Act requires owners or operators of electricity generating units to report $CO_2$ emissions from affected units under the Acid Rain Program. 40 CFR Part 75, which establishes requirements for the monitoring, recordkeeping, and reporting from affected units under the Acid Rain Program, outlines two approaches for determining $CO_2$ emissions using CEMS (see Appendix F of 40 CFR Part 75):

- A monitor measuring $CO_2$ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine $CO_2$ mass emissions. Annual $CO_2$ emissions are determined based on the operating time of the unit.
- A monitor measuring $O_2$ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical $CO_2$ and flue gas production by fuel characteristics can be used to determine $CO_2$ flue gas emissions and $CO_2$ mass emissions. Annual $CO_2$ emissions are determined based on the operating time of the unit.

40 CFR Part 98 also includes these same two approaches for organizations that use a CEMS to report to the GHGRP. If an organization has reported quality assured $CO_2$ emissions data from one of the above CEMS approaches to satisfy their Title IV or GHGRP requirements, it is recommended that they report these same $CO_2$ emissions in their GHG inventory. Organizations that collect $CO_2$ emissions data from a CEMS that does not conform to the specific requirements prescribed under 40 CFR Part 75 or 40 CFR Part 98, and organizations with no CEMS installed, should use the fuel analysis methods outlined in Section 2.2 below. Because a CEMS cannot be used to calculate $CH_4$ and $N_2O$ emissions, organizations should use the fuel analysis method for those emissions.

## 2.2 Fuel Analysis Method

The fuel analysis method to calculate $CO_2$ emissions involves determining a carbon content of fuel combusted using either fuel-specific information or default emission factors, and applying that carbon content to the amount of fuel burned to quantify $CO_2$ emissions.

For affected units under the Acid Rain Program, 40 CFR Part 75 (Appendix G) describes fuel analysis methods for calculating $CO_2$ emissions based on the measured carbon content of the fuel, adjusted for any unburned carbon, and the amount of fuel combusted.[3] For organizations that report under the GHGRP, Subpart C of 40 CFR Part 98 describes fuel analysis methods applicable to that program.

If an organization is measuring and reporting GHG emissions under their Title IV or GHGRP requirements using the fuel analysis methods outlined in 40 CFR Part 75 or 40 CFR Part 98, it is recommended that they report these same emissions in their organizational GHG inventory.

For organizations not reporting GHG emissions under the Acid Rain Program or GHGRP, this guidance provides a fuel analysis method to calculate their GHG emissions. One of three equations below can be used in the fuel analysis method to calculate $CO_2$ emissions for each type of fuel combusted. Two of these equations can also be used to calculate $CH_4$, and $N_2O$ emissions, using appropriate emission factors. The appropriate equation to use depends on what is known about the characteristics of the fuel being consumed.

**Equation 1:**

Emissions = Fuel x $EF_1$

Where:

Emissions = Mass of $CO_2$, $CH_4$, or $N_2O$ emitted

Fuel = Mass or volume of fuel combusted

$EF_1$ = $CO_2$, $CH_4$, or $N_2O$ emission factor per mass or volume unit

Equation 1 is recommended when fuel consumption is known only in mass or volume units, and no information is available about the fuel heat content or carbon content. This equation is the least preferred. It has the most uncertainty because its emission factors are based on default fuel heat content, rather than actual heat content.

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[3] Units reporting $CO_2$ emissions under the Acid Rain Program or GHGRP, through either the CEMS or fuel analysis approach, are required to include $CO_2$ emissions from sorbent use (e.g., limestone used in flue gas desulfurization equipment). Organizations not required to report under these programs should be sure to include any $CO_2$ emissions from sorbent use in their GHG inventory. Procedures to calculate these emissions are outlined in 40 CFR Part 75 Appendix G, Section 3 and 40 CFR Part 98, Subpart C.

Equation 2 is recommended when the actual fuel heat content is provided by the fuel supplier or is otherwise known. It is also recommended when the fuel use is provided in energy units (e.g., therms of natural gas). In such cases, the fuel use in energy units can be multiplied directly by the emission factor ($EF_2$). Equation 2 is a preferable approach over Equation 1 because it uses emission factors that are based on energy units as opposed to mass or volume units. Emission factors based on energy units are less variable than factors per mass or volume units because the carbon content of a fuel is more closely related to the heat content of the fuel than to the total physical quantity of fuel.

**Equation 2:**

Emissions = Fuel x HHV x $EF_2$

Where:

Emissions = Mass of $CO_2$, $CH_4$, or $N_2O$ emitted

Fuel = Mass or volume of fuel combusted

HHV = Fuel heat content (higher heating value),in units of energy per mass or volume of fuel

**$EF_2$** = $CO_2$, $CH_4$, or $N_2O$ emission factor per energy unit

Equation 3 is recommended to calculate $CO_2$ emissions when the actual carbon content of the fuel is known. Carbon content is typically expressed as a percentage by mass, which requires fuel use data in mass units. This equation is most preferred for $CO_2$ calculations because $CO_2$ emissions are directly related to the fuel's carbon content. Because Equation 3 is only applicable to $CO_2$ emissions, Equation 1 or 2 should be used in conjunction to calculate $CH_4$ and $N_2O$ emissions.

**Equation 3:**

Emissions = Fuel x CC x 44/12

Where:

Emissions = Mass of $CO_2$ emitted

Fuel = Mass or volume of fuel combusted

CC = Fuel carbon content, in units of mass of carbon per mass or volume of fuel

44/12 = ratio of molecular weights of $CO_2$ and carbon

Follow the steps below to calculate emissions.

**Step 1: Select the appropriate equation.**

Based on the information available on the characteristics of the fuel being consumed, select the appropriate equation to use in calculating emissions. See the discussion above on the three possible equations.

**Step 2: Determine the amount of fuel combusted.**

Each fuel type should be quantified separately. This can be based on fuel receipts, purchase records, or through direct measurement at the combustion device. If purchase records are used, care should be taken to subtract out any fuel used to produce feedstocks or materials such as plastics where the carbon is ultimately stored. Section 3 describes in more detail the different sources that can be used to determine the amount of fuel combusted and the possible units in which fuel combustion may be measured.

**Step 3: Determine equation inputs.**

The selected equation specifies which inputs are needed to calculate emissions. As appropriate, determine the fuel carbon content, fuel heat content, and/or emission factors associated with each fuel consumed. Further guidance is given in Section 3, and emission factors are provided in Appendix A.

**Step 4: Calculate emissions.**

Use the appropriate equation with the fuel consumption and other equation inputs to calculate the emissions of $CO_2$, $CH_4$, and $N_2O$. Multiply the emissions of $CH_4$ and $N_2O$ by the respective global warming potential (GWP) to calculate $CO_2$-equivalent emissions. The GWPs are 25 for $CH_4$ and 298 for $N_2O$, from the Intergovernmental Panel on Climate Change

(IPCC), Fourth Assessment Report (AR4), 2007. Sum the $CO_2$ equivalent emissions from $CH_4$ and $N_2O$ with the emissions of $CO_2$ to calculate the total $CO_2$-equivalent ($CO_2e$) emissions.

### Example Emissions Calculation

An organization has an on-site natural gas boiler. The organization does not meter the gas that enters the boiler directly. However, the organization does have a record of the natural gas utility bills for the annual reporting period in question. The bills list the amount of fuel purchased in terms of energy (e.g., therms) as well as the cubic feet of gas purchased and the heating value of the gas. It is assumed that there are no fugitive releases of gas, there is no inventory of natural gas stored on-site, and that all the natural gas purchased is combusted (i.e., no feedstock use of gas). The following information is available from the fuel supplier:

Table 1: Example Emissions Calculation

| Month | Amount of Gas Purchased (scf) | Heat Content (Btu/scf) | Amount of Gas Purchased (therms) |
|---|---|---|---|
| January | 550,000 | 1,025 | 5,637.5 |
| February | 580,000 | 1,025 | 5,945 |
| March | 530,000 | 1,025 | 5,432.5 |
| April | 480,000 | 1,025 | 4,920 |
| May | 500,000 | 1,025 | 5,125 |
| June | 490,000 | 1,025 | 5,022.5 |
| July | 510,000 | 1,025 | 5,227.5 |
| August | 390,000 | 1,025 | 3,997.5 |
| September | 480,000 | 1,025 | 4,920 |
| October | 540,000 | 1,025 | 5,535 |
| November | 490,000 | 1,025 | 5,022.5 |
| December | 460,000 | 1,025 | 4,715 |
| Total | 6,000,000 | | 61,500 |

Note: scf = standard cubic feet, 1 therm = 100,000 Btu

**Step 1**: The amount of fuel combusted has been determined based on purchase data on utility bills from the supplier.

**Step 2**: Carbon content is not known, so Equation 3 cannot be used. Sufficient information is available to use either Equation 1 or 2, because fuel consumption and actual fuel heat content are available. Equation 2 is selected because this is the preferred approach if the actual fuel heat content is known.

**Step 3**: Fuel heat content has been provided by the supplier. Table A-1 is used to determine the emission factors per energy unit for natural gas: 53.06 kg $CO_2$/mmBtu, 1.0 g $CH_4$/mmBtu, 0.10 g $N_2O$/mmBtu.

**Step 4**: The emissions are calculated as follows:

Natural use is converted to mmBtu: 61,500 therms × 0.1 mmBtu/therm = 6,150 mmBtu

Because fuel use is known in energy units, it can be multiplied directly by emission factors:

6,150 mmBtu × 53.06 kg $CO_2$/mmBtu × $10^{-3}$ metric tons/kg = 326.3 metric tons $CO_2$

6,150 mmBtu × 1.0 g $CH_4$/mmBtu × $10^{-3}$ kg/g = 6.15 kg $CH_4$

6,150 mmBtu × 0.10 g $N_2O$/mmBtu × $10^{-3}$ kg/g = 0.615 kg $N_2O$

$CH_4$ and $N_2O$ emissions are converted to $CO_2$ equivalent emissions:
6.15 kg $CH_4$ × 25 GWP × $10^{-3}$ metric tons/kg = 0.2 metric tons $CO_2e$
0.615 kg $N_2O$ × 298 GWP × $10^{-3}$ metric tons/kg = 0.2 metric tons $CO_2e$

The $CO_2e$ emissions from $CH_4$ and $N_2O$ are summed with the emissions of $CO_2$ to calculate total $CO_2e$ emissions:

326.3 metric tons $CO_2$ + 0.2 metric tons $CO_2e$ + 0.2 metric tons $CO_2e$ = 326.7 metric tons $CO_2e$

# Section 3: Choice of Activity Data and Emission Factors

This section discusses choices of activity data and factors used for calculating emissions with the default fuel analysis method provided in Section 2.2. This guidance has been structured to accommodate a wide range of organizations with varying levels of information and measurements in various units. If the organization has a CEMS installed or has carbon content data based on fuel sampling information, it should refer to guidance in 40 CFR Part 75 or 40 CFR Part 98 to calculate $CO_2$ emissions. In the case of systems with more than one exhaust stack, such as those with a heat recovery system generator (HRSG) or duct burner, a CEMS may not account for all combustion emissions.

## 3.1 Activity Data Sources

When calculating GHG emissions with the fuel analysis method, the first piece of information that needs to be determined is the quantity of fuel combusted for each fuel type. One method of determining the amount of fuel combusted at a facility is to measure the fuel input into each combustion device and to sum the measured data of each combustion device in the facility. Typical fuel measurement systems measure the volume of fuel combusted, such as fuel flow meters for natural gas and fuel oil, or the weight of fuel combusted, such as coal feed belt scales.

If fuel use data are not directly measured then fuel purchase records can be used to determine the amount of fuel combusted. Records could include monthly utility bills for natural gas or periodic invoices for deliveries of fuel oil. If a particular fuel type is used for both stationary and mobile sources, care should be taken to avoid double counting the fuel use.

Commodity natural gas may be purchased from a provider other than the local distribution utility. In this situation, the reporting organization may receive natural gas invoices from both the commodity supplier as well as from the local distribution utility, who charges a fee for gas deliveries. It is recommended that the consumption from the local utility be used as the activity data, because this is based on fuel meters located at the organization's facility. To avoid counting the same consumption twice, ensure that consumption from the commodity supplier is not also included in the activity data.

**Equation 4:** Accounting for Changes in Fuel Inventory

$$\text{Fuel B} = \text{Fuel P} + (\text{Fuel } S_T - \text{Fuel } S_E)$$

where:

Fuel B = Fuel burned in reporting period

Fuel P = Fuel purchased in reporting period

Fuel $S_T$ = Fuel stock at start of reporting period

Fuel $S_E$ = Fuel stock at end of reporting period

There are several factors that could lead to differences between the amount of fuel purchased and the amount of fuel actually combusted during a reporting period, for example:

- Changes in fuel storage inventory
- Fuel used as feedstock
- Fugitive releases or fuel spills

For changes in fuel storage inventory, Equation 4 can be used to calculate actual fuel use. Fuel purchase data are usually reported as the amount of fuel provided by a supplier as it crosses the gate of the facility. However, once fuel enters the facility there could be some losses before it actually reaches the combustion device. Before calculating emissions, organizations should subtract the amount of fuel lost in fugitive releases or spills from the amount of fuel purchased. These losses are particularly important for natural gas, which could be lost due to fugitive releases from facility valves and piping, as these fugitive emissions could be significant. These fugitive natural gas releases (essentially methane emissions) should be accounted for separately from combustion emissions.

Purchased fuels could also be used as feedstock for products produced by the reporting organization. In this case the carbon in the fuel would be stored in the product as opposed to being released through combustion. In their scope 1 emissions, organizations only include direct emissions from their facilities. If carbon leaves the facility stored in a product, even if the product is subsequently burned or otherwise releases the stored carbon, this would be included in an organization's scope 3 emissions, not their scope 1 emissions. Therefore, organizations should subtract any amount of fuel that is used as feedstock from the amount of fuel purchased before calculating scope 1 emissions.

For certain equipment, such as emergency generators, gathering fuel consumption data through direct measurement or based on fuel purchases may not be practical. If such equipment generally represents an insignificant source of GHG emissions, an acceptable method to estimate fuel consumption is to multiply measured or estimated operating hours by the hourly fuel consumption rate.

If fuel consumption data are not available for certain facilities or operations, an estimate should be made for completeness. The fraction of total GHG emissions that is estimated should be limited so as not to have a significant impact on accuracy. If the organization is one of many tenants in a facility and does not have the actual amount of fuel used in its space, the organization may estimate its fuel consumption by multiplying the fuel use of the entire facility by the percentage of the floor area that the organization occupies. Organizations may also estimate fuel consumption using published values for average energy consumption per square foot of floor area. For example, such values are provided by the U.S. Energy Information Administration's Commercial Building Energy Consumption Survey.

## 3.2 Activity Data Units

Fuel is measured in terms of physical units (i.e., mass or volume). For organizations that directly measure their own fuel consumption, it is recommended that they track fuel use in terms of these physical units as they represent the primary measurement data. Organizations that do not directly measure how much fuel they use need to rely on data from fuel suppliers. Suppliers may provide data in physical units or in energy units (e.g., therms of natural gas). Suppliers may also be able to provide data on carbon content or heat content of the fuel, which is discussed further in Section 3.3.

It is possible that organizations may only know the cost of fuels purchased. This is the least accurate method of determining fuel use and is not recommended for GHG reporting. If the amount spent on fuel is the only information initially available, it is recommended that organizations contact their fuel supplier to request data in physical or energy units. If absolutely no other information is available, organizations should use fuel prices to convert the amount spent to physical or energy units, and should document the prices used. Price varies widely for specific fuels, especially over the geographic area and timeframe typically established for reporting GHG emissions.

The approaches for measuring or recording the amount of fuel used are listed in order of preference below.

1. An organization has fuel consumption data by fuel type in terms of physical units either measured on site or provided by a supplier with accurate data on carbon content of the specific fuel as determined by the fuel supplier or by fuel sampling and analysis (see Section 3.3).
2. An organization has fuel consumption data by fuel type in terms of physical units with accurate data on heat content of the specific fuel as determined by the fuel supplier or by fuel sampling and analysis (see Section 3.3). Alternatively, organization has fuel consumption data from the supplier in energy units.

3. An organization has data on the physical quantity of fuel purchased but not the carbon or heat content.
4. An organization only has data on cost of fuels purchased and has to convert to physical quantity based on dividing total expenditures by average prices.

## 3.3 Fuel Carbon Content and Heat Content

Emissions of $CO_2$ from fuel combustion are dependent on the amount of carbon in the fuel, which is specific to the fuel type and grade of the fuel. It is recommended that organizations determine the actual carbon content of the fuels consumed, if possible. The most accurate method to determine a fuel's carbon content data is through chemical analysis of the fuel. This data may be obtained directly from the fuel supplier.

Carbon content can also be determined by fuel sampling and analysis. Fuel sampling and analysis should be performed periodically with the frequency dependent on the type of fuel. The sampling frequency should be greater for more variable fuels (e.g., coal, wood, MSW) than for more homogenous fuels (e.g., natural gas, fuel oil). The sampling and analysis methodologies used should be detailed in the organization's Inventory Management Plan (IMP). Refer to 40 CFR Part 75, Appendix G or 40 CFR Part 98, Subpart C for recommended sampling rates and methods.

If actual fuel carbon content is available, either from the supplier or from sampling and analysis, Equation 3 in Section 2.2 may be used to calculate $CO_2$ emissions. Because Equation 3 is only applicable to $CO_2$ emissions, Equation 1 or 2 should be used in conjunction to calculate $CH_4$ and $N_2O$ emissions. It is also good practice to track the carbon content values used and to indicate if they vary over time.

If carbon content is not available, it is recommended that organizations determine the actual heat content of the fuel, if possible. The heat content of purchased fuel is often known and provided by the fuel supplier because it is directly related to the useful output or value of the fuel. Heat content can also be determined by fuel sampling and analysis, using methods discussed above. It is recommended that organizations use heat contents determined by one of these methods rather than default heat content, as these should better represent the characteristics of the specific fuel consumed. If actual fuel heat content is available, either from the supplier or from sampling and analysis, then Equation 2 in Section 2.2 may be used to calculate $CO_2$, $CH_4$, and $N_2O$ emissions. It is also good practice to track the heat content values used and to indicate if they vary over time.

When determining fuel heat content or tracking fuel use data in energy units, it is important to distinguish between lower heating values (LHV) and higher heating values (HHV), also called net calorific value and gross calorific value, respectively. Heating values describe the amount of energy released when a fuel is burned completely, and LHV and HHV are different methods to measure the amount of energy released. A given fuel, therefore, always has both a LHV and a HHV. The LHV assumes that the steam released during combustion remains as a gas. The HHV assumes that the steam is condensed to a liquid, thus releasing more energy. HHV is typically used in the U.S. and in Canada, while other countries typically use LHV.

All emission factors and default heat content values in this guidance are based on HHV. Therefore, if fuel consumption is measured in LHV units, this must be converted to HHV before calculating emissions. To convert from LHV to HHV, a simplified convention used by the International Energy Agency can be used. For coal and petroleum, divide energy in LHV by 0.95. For natural gas, divide by 0.90.

## 3.4 Emission Factors

If actual fuel carbon content is not available, the fuel analysis method for calculating emissions relies on default emission factors. These factors approximate the carbon content of fuel to quantify the amount of $CO_2$ that will be released when the fuel is combusted. Emission factors also assume typical combustion technology to quantify the amount of $CH_4$ and $N_2O$ that will be released.

Appendix A provides two main types of default emission factors: factors defined per unit of fuel mass or volume (Table A-1 and A-2), and factors defined by per unit of fuel energy content (Table A-3 and A-4). As discussed in Section 2.2, using the emission factors per energy unit, along with Equation 2, is preferable to using emission factors per mass or volume.

Not all stationary combustion devices burn standard fuels. Combustion devices could also burn waste fuels, for example, MSW, with mixed biomass and fossil carbon content. Flares and thermal oxidizers could burn waste gas streams. These combustion sources and waste fuels are treated like other combustion sources and fuel types. If the carbon content of the waste fuel is known, Equation 3 can be used to quantify emissions. If the carbon content is not known, determining the appropriate emission factors can be challenging due to the variability and non-standardized nature of waste fuels. Emission factors are provided in Appendix A for waste fuels such as MSW, tires, and used oil. For more complex waste gas streams, an example calculation is provided below. If none of these options are possible, emission factors for some waste fuels can be determined by using the emission factor for a fuel that most closely represents the waste fuel.

**Example: Determining an Emission Factor for a Gas Waste Stream**

An organization has a thermal oxidizer destroying a waste gas stream of different components. The organization has data on volume of gas combusted and on the mole fraction of the different components of the waste gas stream.

**Equation 5: Determining Emission Factor for Gas Waste Stream**

$$\text{Emission Factor}\left(\frac{\text{lb C}}{\text{ft}^3\ \text{gas}}\right)=\sum_{i=1}^{n} MF_i \times MC_{gas} \times m.w._i \times CF_i$$

**Where:**

$MF_i$ = Molar fraction of gas component i $\left(\frac{\text{lb-mole i}}{\text{lb-mole gas}}\right)$

$MC_{gas}$ = Molar concentration of gas $\left(\frac{\text{lb-mole gas}}{\text{ft}^3\ \text{gas}}\right)$

$m.w._i$ = Molecular weight of gas component i $\left(\frac{\text{lb i}}{\text{lb-mole i}}\right)$

$CF_i$ = Carbon fraction of gas component i $\left(\frac{\text{lb C}}{\text{lb i}}\right)$

The first step is to determine the total number of moles in the waste stream per a specific volume. This step is based on the assumed temperature and pressure of the gas. Assuming conditions of 1 atm and 25° C, there are 2.55 x 10-3 lb mole of gas per cubic foot of gas. This factor could be adjusted to meet the specific temperature and pressure conditions of the organization's waste gas stream. An emission factor is then determined per cubic feet of gas based on the following Equation 5.

The following Table 2 shows an example gas waste stream with the mole fractions of different components.

Table 2: Example Gas Waste Stream

| Gas Component | MF | MC | m.w. | CF | Lb C / $ft^3$ gas |
|---|---|---|---|---|---|
| $CO_2$ | 5% | $2.55 \times 10^{-3}$ | 44 | 27% | 0.0015 |
| $CH_4$ | 30% | $2.55 \times 10^{-3}$ | 16 | 75% | 0.0092 |
| $C_3H_8$ | 20% | $2.55 \times 10^{-3}$ | 44 | 82% | 0.018 |
| $C_6H_6$ | 35% | $2.55 \times 10^{-3}$ | 78 | 92% | 0.064 |
| Other non-C | 10% | $2.55 \times 10^{-3}$ | - | 0% | 0.0 |
| Total | 100% | - | - | - | 0.093 |

Based on Table 2 it can be seen that the emission factor for this example gas waste stream is 0.093 lb C per $ft^3$ of waste gas. To obtain total $CO_2$ emissions from this waste gas combustion, the emission factor can be multiplied by the total amount of gas combusted and by 44/12, the ratio of the molecular weights of $CO_2$ and carbon.

# Section 4: Completeness

In order for an organization's GHG inventory to be complete it must include all emission sources within the organization's chosen inventory boundaries. See Chapter 3 of the GHG Protocol for detailed guidance on setting organizational boundaries and Chapter 4 of the GHG Protocol for detailed guidance on setting operational boundaries of the inventory.

On an organizational level, the inventory should include emissions from all applicable facilities or fleets of vehicles. Completeness of organization-wide emissions can be checked by comparing the list of sources included in the GHG emissions inventory with those included in other emissions inventories, environmental reporting, financial reporting, etc.

At the operational level, an organization should include all GHG emissions from the sources included in their inventory. Possible GHG emission sources are stationary fuel combustion, combustion of fuels in mobile sources, purchases of electricity, emissions from air conditioning equipment, and process or fugitive emissions. Organizations may refer to this guidance document for calculating emissions from stationary combustion sources and to the Center's GHG Guidance documents for calculating emissions from other sources. Operational completeness of stationary combustion sources can be checked by comparing the sources included in the GHG inventory with those reported under regulatory programs (e.g., Title V air permit), or in annual fuel use surveys. Examples of typical types of fuel combustion sources that should be included are as follows:

- Boilers/furnaces
- Internal combustion engines
- Turbines
- Flares
- Process heaters/ovens
- Incinerators
- Cooling systems (e.g., natural gas chillers)

As described in Chapter 1 of the GHG Protocol, there is no materiality threshold set for reporting emissions. The materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources.

# Section 5: Uncertainty Assessment

There is uncertainty associated with all methods of calculating $CO_2$, $CH_4$, and $N_2O$ emissions from stationary combustion sources.

EPA does not recommend that organizations quantify uncertainty as +/- % of emissions or in terms of data quality indicators.

It is recommended that organizations attempt to identify the areas of uncertainty in their emissions calculations and make an effort to use the most accurate data possible. If the CEMS approach is used to calculate emissions, it is recommended that the organization follow the QA/QC guidance and good practices associated with that method as outlined in the Acid Rain Program Rule[4] or in 40 CFR Part 98. Entities utilizing CEMS to comply with Clean Air Act regulations are required to develop a quality assurance plan. This plan should address $CO_2$ emissions measurement.

The accuracy of calculating emissions from fuel combustion in stationary sources from the fuel analysis method is partially determined by the availability of data on the amount of fuel consumed or purchased. If the amount of fuel combusted is directly measured or metered before entering the combustion device, then the resulting uncertainty should be fairly low. Data on the quantity of fuel purchased should also be an accurate representation of fuel combusted, provided that any necessary adjustments are made for changes in fuel inventory, fuel used as feedstock, fugitive releases, or spills. Uncertainty will be higher if only prices of fuels purchased are used to estimate fuel consumption, or if an estimation approach is used.

The accuracy of calculating emissions from stationary combustion sources with the fuel analysis method is also determined by the factors used to convert fuel use into emissions. Uncertainty in the factors is primarily due to the accuracy in which they are measured, and the variability of the supply source. For example, carbon content factors for coal vary greatly, depending on its characteristics, chemical properties, and annual fluctuations in the fuel quality. Therefore, using the U.S. default emission factors for coal may result in greater uncertainty than for other fuels if the local fuel supplies do not match the default fuel characteristics.

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[4] Part 75.21 and Appendix B of the regulation discuss the QA/QC plan.

# Section 6: Documentation

In order to ensure that emissions calculations are transparent and verifiable, the documentation sources listed in Table 1 should be maintained. These documentation sources should be collected to ensure the accuracy and transparency of the related emissions and should also be included in the organization's Inventory Management Plan (IMP).

Table 3: Documentation Sources for Stationary Combustion

| Data | Documentation Source |
|---|---|
| Fuel consumption data | Purchase receipts or utility bills; delivery receipts; contract purchase or firm purchase records; stock inventory documentation; metered fuel documentation |
| Heat contents and carbon contents used other than defaults provided | Purchase receipts or utility bills; delivery receipts; contract purchase or firm purchase records; other documentation from suppliers; EIA, EPA, or industry reports |
| Prices used to convert cost of fuels purchased to amount or energy content of fuel consumed | Purchase receipts; delivery receipts; contract purchase or firm purchase records; EIA, EPA, or industry reports |
| All assumptions made in calculating fuel consumption, heat contents, and emission factors | All applicable sources |

# Section 7: Inventory Quality Assurance and Quality Control

Chapter 7 of the GHG Protocol provides general guidelines for implementing a QA/QC process for all emissions calculations. For stationary combustion sources, activity data and emission factors can be verified using a variety of approaches:

- Fuel consumption data by source or facility can be compared with fuel purchasing data, taking into account any changes in inventory.
- Fuel energy use data can be compared with data provided to the U.S. Department of Energy or other U.S. Environmental Protection Agency reports or surveys.
- If emission calculations were obtained from CEMS, this data can be compared to emissions calculated using the fuel analysis method.
- If any emission factors were calculated or obtained from the fuel supplier, these factors can be compared to U.S. average emission factors.
- The rate at which suppliers change/update heating values can be examined to approximate accuracy.
- Depending on the end-use, some non-energy uses of fossil fuels, such as for manufacturing plant feedstocks, can result in long term storage of some or all of the carbon contained in the fuel. This guidance addresses fuel use for combustion purposes only. Therefore, all fuel consumption for other purposes should be excluded from this analysis.
- Examining the quality control associated with equipment used for facility level fuel measurements and equipment used to calculate site-specific emission factors, or emissions.

# Appendix A: Default Emission Factors

This appendix contains default factors for use in calculating emissions from the fuel analysis method described in Section 2.2 of this document.

The emission factors in Table A-1 and A-2 can be used in Equation 1 from Section 2.2 to calculate GHG emissions if fuel use is known only in mass or volume units, and no information is available about the fuel heat content or carbon content. These emission factors are developed by multiplying the emission factors in Table A-3 and A-4 by the default heat content of the fuels, which is also shown in Table A-1 and A-2.

The emission factors in Table A-3 and A-4 can be used in Equation 2 from Section 2.2 to calculate GHG emissions when the actual fuel heat content is known or when the fuel use is provided in energy units.

All $CO_2$ emission factors assume that 100% of the carbon content of the fuel is oxidized to $CO_2$, as is recommended by the Intergovernmental Panel on Climate Change (IPCC).

The $CH_4$ and $N_2O$ emission factors provided represent emissions in terms of fuel type and assume typical combustion technology for industry. Other references, including those listed below, provide emission factors by end-use sector (i.e., residential, commercial, industrial, electricity generation) or by more specific combustion technology type (e.g., natural gas industrial boilers >293 MW). These references are recommended for organizations interested in performing a more accurate calculation of $CH_4$ and $N_2O$ emissions.

- Intergovernmental Panel on Climate Change (IPCC). 2006. Guidelines for National Greenhouse Gas Inventories, Intergovernmental Panel on Climate Change, Organization for Economic Co-Operation and Development. Paris, France.
- U.S. EPA 1995. Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources, 5th edition, Supplements A, B, C, D, E, F, Updates 2001-2011, AP-42, U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

Table A-1: Emission Factors for Equation 1 ($EF_1$) - Emissions per Mass or Volume Unit for Fossil Fuel Combustion

| Fuel | Heat Content (HHV) | Emission Factors | | |
|---|---|---|---|---|
| **Coal and Coke** | (mmBtu/ton) | (kg $CO_2$/ton) | (g $CH_4$/ton) | (g $N_2O$/ton) |
| Anthracite Coal | 25.09 | 2,602 | 276 | 40 |
| Bituminous Coal | 24.93 | 2,325 | 274 | 40 |
| Sub-bituminous Coal | 17.25 | 1,676 | 190 | 28 |
| Lignite Coal | 14.21 | 1,389 | 156 | 23 |
| Mixed (Commercial Sector) | 21.39 | 2,016 | 235 | 34 |
| Mixed (Electric Power Sector) | 19.73 | 1,885 | 217 | 32 |
| Mixed (Industrial Coking) | 26.28 | 2,468 | 289 | 42 |
| Mixed (Industrial Sector) | 22.35 | 2,116 | 246 | 36 |
| Coal Coke | 24.80 | 2,819 | 273 | 40 |

Table A-1: Emission Factors for Equation 1 ($EF_1$) - Emissions per Mass or Volume Unit for Fossil Fuel Combustion

| Fuel | Heat Content (HHV) | Emission Factors | | |
|---|---|---|---|---|
| **Fossil Fuel-derived Fuels (Solid)** | (mmBtu/ton) | (kg $CO_2$/ton) | (g $CH_4$/ton) | (g $N_2O$/ton) |
| Municipal Solid Waste | 9.95 | 902 | 318 | 42 |
| Petroleum Coke (Solid) | 30.00 | 3,072 | 960 | 126 |
| Plastics | 38.00 | 2,850 | 1,216 | 160 |
| Tires | 28.00 | 2,407 | 896 | 118 |
| **Natural Gas** | (mmBtu/scf) | (kg $CO_2$/scf) | (g $CH_4$/scf) | (g $N_2O$/scf) |
| Natural gas | 0.001026 | 0.05444 | 0.00103 | 0.00010 |
| **Fossil Fuel-derived Fuels (gaseous)** | (mmBtu/scf) | (kg $CO_2$/scf) | (g $CH_4$/scf) | (g $N_2O$/scf) |
| Blast Furnace Gas | 0.000092 | 0.02524 | 0.000002 | 0.000009 |
| Coke Oven Gas | 0.000599 | 0.02806 | 0.000288 | 0.000060 |
| Fuel Gas | 0.001388 | 0.08189 | 0.004164 | 0.000833 |
| Propane Gas | 0.002516 | 0.15463 | 0. 007548 | 0.001510 |
| **Petroleum Products** | (mmBtu/gal) | (kg $CO_2$/gal) | (g $CH_4$/gal) | (g $N_2O$/gal) |
| Asphalt and Road Oil | 0.158 | 11.91 | 0.47 | 0.09 |
| Aviation Gasoline | 0.120 | 8.31 | 0.36 | 0.07 |
| Butane | 0.103 | 6.67 | 0.31 | 0.06 |
| Butylene | 0.105 | 7.22 | 0.32 | 0.06 |
| Crude Oil | 0.138 | 10.29 | 0.41 | 0.08 |
| Distillate Fuel Oil No. 1 | 0.139 | 10.18 | 0.42 | 0.08 |
| Distillate Fuel Oil No. 2 | 0.138 | 10.21 | 0.41 | 0.08 |
| Distillate Fuel Oil No. 4 | 0.146 | 10.96 | 0.44 | 0.09 |
| Ethane | 0.068 | 4.05 | 0.20 | 0.04 |
| Ethylene | 0.058 | 3.83 | 0.17 | 0.03 |
| Heavy Gas Oils | 0.148 | 11.09 | 0.44 | 0.09 |
| Isobutane | 0.099 | 6.43 | 0.30 | 0.06 |
| Isobutylene | 0.103 | 7.09 | 0.31 | 0.06 |
| Kerosene | 0.135 | 10.15 | 0.41 | 0.08 |
| Kerosene-type Jet Fuel | 0.135 | 9.75 | 0.41 | 0.08 |
| Liquefied Petroleum Gases (LPG) | 0.092 | 5.68 | 0.28 | 0.06 |
| Lubricants | 0.144 | 10.69 | 0.43 | 0.09 |
| Motor Gasoline | 0.125 | 8.78 | 0.38 | 0.08 |
| Naphtha (<401 deg F) | 0.125 | 8.50 | 0.38 | 0.08 |
| Natural Gasoline | 0.110 | 7.36 | 0.33 | 0.07 |
| Other Oil (>401 deg F) | 0.139 | 10.59 | 0.42 | 0.08 |
| Pentanes Plus | 0.110 | 7.70 | 0.33 | 0.07 |
| Petrochemical Feedstocks | 0.125 | 8.88 | 0.38 | 0.08 |
| Petroleum Coke | 0.143 | 14.64 | 0.43 | 0.09 |
| Propane | 0.091 | 5.72 | 0.27 | 0.05 |

Table A-1: Emission Factors for Equation 1 ($EF_1$) - Emissions per Mass or Volume Unit for Fossil Fuel Combustion

| Fuel | Heat Content (HHV) | | Emission Factors | |
|---|---|---|---|---|
| Propylene | 0.091 | 6.17 | 0.27 | 0.05 |
| Residual Fuel Oil No. 5 | 0.140 | 10.21 | 0.42 | 0.08 |
| Residual Fuel Oil No. 6 | 0.150 | 11.27 | 0.45 | 0.09 |
| Special Naphtha | 0.125 | 9.04 | 0.38 | 0.08 |
| Unfinished Oils | 0.139 | 10.36 | 0.42 | 0.08 |
| Used Oil | 0.138 | 10.21 | 0.41 | 0.08 |

Table A-2: Emission Factors for Equation 1 ($EF_1$) - Emissions per Mass or Volume Unit for Biomass Fuel Combustion

| Fuel | Heat Content (HHV) | | Emission Factors | |
|---|---|---|---|---|
| **Biomass Fuels (Solid)** | (mmBtu/ton) | (kg $CO_2$/ton) | (g $CH_4$/ton) | (g $N_2O$/ton) |
| Agricultural Byproducts | 8.25 | 975 | 264 | 35 |
| Peat | 8.00 | 895 | 256 | 34 |
| Solid Byproducts | 10.39 | 1,096 | 332 | 44 |
| Wood and Wood Residuals | 17.48 | 1,640 | 126 | 63 |
| | | | | |
| **Fossil Fuel-derived Fuels (Solid)** | (mmBtu/scf) | (kg $CO_2$/scf) | (g $CH_4$/scf) | (g $N_2O$/scf) |
| Landfill Gas | 0.000485 | 0.025254 | 0.001552 | 0.000306 |
| Other Biomass Gases | 0.000655 | 0.034106 | 0.002096 | 0.000413 |
| | | | | |
| **Biomass Fuels (Liquid)** | (mmBtu/gal) | (kg CO2/gal) | (g CH4/gal) | (g N2O/gal) |
| Biodiesel (100%) | 0.128 | 9.45 | 0.14 | 0.01 |
| Ethanol (100%) | 0.084 | 5.75 | 0.09 | 0.01 |
| Rendered Animal Fat | 0.125 | 8.88 | 0.14 | 0.01 |
| Vegetable Oil | 0.120 | 9.79 | 0.13 | 0.01 |

**Table A-3: Emission Factors for Equation 2 ($EF_2$) - Emissions per Energy Unit for Fossil Fuel Combustion**

| Fuel | | Emission Factors | |
|---|---|---|---|
| **Coal and Coke** | (kg $CO_2$/mmBtu) | (g $CH_4$/ mmBtu) | (g $N_2O$/ mmBtu) |
| Anthracite Coal | 103.69 | 11 | 1.6 |
| Bituminous Coal | 93.28 | 11 | 1.6 |
| Sub-bituminous Coal | 97.17 | 11 | 1.6 |
| Lignite Coal | 97.72 | 11 | 1.6 |
| Mixed (Commercial Sector) | 94.27 | 11 | 1.6 |
| Mixed (Electric Power Sector) | 95.52 | 11 | 1.6 |
| Mixed (Industrial Coking) | 93.90 | 11 | 1.6 |
| Mixed (Industrial Sector) | 94.67 | 11 | 1.6 |

**Table A-3: Emission Factors for Equation 2 (EF$_2$) - Emissions per Energy Unit for Fossil Fuel Combustion**

| Fuel | Emission Factors | | |
|---|---|---|---|
| Coal Coke | 113.67 | 11 | 1.6 |
| | | | |
| **Fossil Fuel-derived Fuels (Solid)** | | | |
| Municipal Solid Waste | 90.70 | 32 | 4.2 |
| Petroleum Coke (Solid) | 102.41 | 32 | 4.2 |
| Plastics | 75.00 | 32 | 4.2 |
| Tires | 85.97 | 32 | 4.2 |
| | | | |
| **Natural Gas** | | | |
| Natural Gas | 53.06 | 1.0 | 0.10 |
| | | | |
| **Fossil Fuel-derived Fuels (gaseous)** | | | |
| Blast Furnace Gas | 274.32 | 0.022 | 0.10 |
| Coke Oven Gas | 46.85 | 0.48 | 0.10 |
| Fuel Gas | 59.00 | 3.0 | 0.60 |
| Propane Gas | 61.46 | 3.0 | 0.60 |
| | | | |
| **Petroleum Products** | | | |
| Asphalt and Road Oil | 75.36 | 3.0 | 0.60 |
| Aviation Gasoline | 69.25 | 3.0 | 0.60 |
| Butane | 64.77 | 3.0 | 0.60 |
| Butylene | 68.72 | 3.0 | 0.60 |
| Crude Oil | 74.54 | 3.0 | 0.60 |
| Distillate Fuel Oil No. 1 | 73.25 | 3.0 | 0.60 |
| Distillate Fuel Oil No. 2 | 73.96 | 3.0 | 0.60 |
| Distillate Fuel Oil No. 4 | 75.04 | 3.0 | 0.60 |
| Ethane | 59.60 | 3.0 | 0.60 |
| Ethylene | 65.96 | 3.0 | 0.60 |
| Heavy Gas Oils | 74.92 | 3.0 | 0.60 |
| Isobutane | 64.94 | 3.0 | 0.60 |
| Isobutylene | 68.86 | 3.0 | 0.60 |
| Kerosene | 75.20 | 3.0 | 0.60 |
| Kerosene-type Jet Fuel | 72.22 | 3.0 | 0.60 |
| Liquefied Petroleum Gases (LPG) | 61.71 | 3.0 | 0.60 |
| Lubricants | 74.27 | 3.0 | 0.60 |
| Motor Gasoline | 70.22 | 3.0 | 0.60 |
| Naphtha (<401 deg F) | 68.02 | 3.0 | 0.60 |
| Natural Gasoline | 66.88 | 3.0 | 0.60 |
| Other Oil (>401 deg F) | 76.22 | 3.0 | 0.60 |
| Pentanes Plus | 70.02 | 3.0 | 0.60 |
| Petrochemical Feedstocks | 71.02 | 3.0 | 0.60 |
| Petroleum Coke | 102.41 | 3.0 | 0.60 |
| Propane | 62.87 | 3.0 | 0.60 |

**Table A-3: Emission Factors for Equation 2 ($EF_2$) - Emissions per Energy Unit for Fossil Fuel Combustion**

| Fuel | | Emission Factors | |
|---|---|---|---|
| Propylene | 67.77 | 3.0 | 0.60 |
| Residual Fuel Oil No. 5 | 72.93 | 3.0 | 0.60 |
| Residual Fuel Oil No. 6 | 75.10 | 3.0 | 0.60 |
| Special Naphtha | 72.34 | 3.0 | 0.60 |
| Unfinished Oils | 74.54 | 3.0 | 0.60 |
| Used Oil | 74.00 | 3.0 | 0.60 |

**Table A-4: Emission Factors for Equation 2 ($EF_2$) - Emissions per Energy Unit for Biomass Fuel Combustion**

| Fuel | | Emission Factors | |
|---|---|---|---|
| **Biomass Fuels (Solid)** | (kg $CO_2$/mmBtu) | (g $CH_4$/ mmBtu) | (g $N_2O$/ mmBtu) |
| Agricultural Byproducts | 118.17 | 32 | 4.2 |
| Peat | 111.84 | 32 | 4.2 |
| Solid Byproducts | 105.51 | 32 | 4.2 |
| Wood and Wood Residuals | 93.80 | 7.2 | 3.6 |
| **Biomass Fuels (Gaseous)** | | | |
| Landfill Gas | 52.07 | 3.2 | 0.63 |
| Other Biomass Gases | 52.07 | 3.2 | 0.63 |
| **Biomass Fuels (Liquid)** | | | |
| Biodiesel (100%) | 73.84 | 1.1 | 0.11 |
| Ethanol (100%) | 68.44 | 1.1 | 0.11 |
| Rendered Animal Fat | 71.06 | 1.1 | 0.11 |
| Vegetable Oil | 81.55 | 1.1 | 0.11 |
| **Biomass Fuels (Kraft Pulping Liquor, by Wood Furnish)** | | | |
| North American Softwood | 94.4 | 1.9 | 0.42 |
| North American Hardwood | 93.7 | 1.9 | 0.42 |
| Bagasse | 95.5 | 1.9 | 0.42 |
| Bamboo | 93.7 | 1.9 | 0.42 |
| Straw | 95.1 | 1.9 | 0.42 |

Source for the emission factors in this appendix: Federal Register EPA; 40 CFR Part 98; e-CFR, June 13, 2017 (see link below). Table C-1, Table C-2, Table AA-1. https://www.ecfr.gov/cgi-bin/text-idx?SID=ae265d7d6f98ec86fcd8640b9793a3f6&mc=true&node=pt40.23.98&rgn=div5#ap40.23.98_19.1