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CLIMATE LEADERS

GREENHOUSE GAS INVENTORY PROTOCOL CORE MODULE GUIDANCE

Indirect Emissions from **Purchases/Sales of Electricity and Steam**

CLIMATE LEADERS
U.S. Environmental Protection Agency

The Climate Leaders Greenhouse Gas Inventory Protocol is based on the Greenhouse Gas Protocol (GHG Protocol) developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). The GHG Protocol consists of corporate accounting and reporting standards and separate calculation tools. The Climate Leaders Greenhouse Gas Inventory Protocol is an effort by EPA to enhance the GHG Protocol to fit more precisely what is needed for Climate Leaders. The Climate Leaders Greenhouse Gas Protocol consists of the following components:

- Design Principles Guidance
- Core Modules Guidance
- Optional Modules Guidance

All changes and additions to the GHG Protocol made by Climate Leaders are summarized in the Climate Leaders Greenhouse Gas Inventory Protocol Design Principles Guidance.

For more information regarding the Climate Leaders Program, visit us on the Web at www.epa.gov/climateleaders.

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Introduction

Indirect emissions are those that result from a Climate Leaders Partner's activities, but are actually emitted from sources owned by other entities. A major source of indirect emissions occurs through the use of purchased electricity or steam. Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are emitted to the atmosphere as fossil fuels are burned to produce heat and power. Therefore, manufacturing operations and other activities that use purchased electricity or steam indirectly cause emissions of greenhouse gases (GHG). The resulting emissions depend on the amount of energy used and the mix of fuel that goes into producing this electricity or steam. EPA requires that Partners report the indirect emissions associated with their use of purchased steam and electricity. This document presents guidance on estimating GHG indirect emissions resulting from these sources. This module also provides guidance on reporting emissions from the sales of steam and electricity by non-utilities.

1.1. Non-Utility Sales of Electricity or Steam

Manufacturing or processing facilities can have onsite power plants that produce electricity and/or steam to meet the demand of that facility. If there is excess capacity, the facility may sell a portion of the electricity and/or steam output to another company directly or to the grid. Non-utility Partners' facilities (where heat or power is not the primary output of the facility) that sell excess electricity and/or steam report the emissions from producing the electricity and/or steam as direct emissions. This is done using the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*. The facility could also report the emissions associated with the heat or power sales as supplemental information in their Climate Leaders inventory. The emissions from energy sales are not included when calculating a Partner's progress towards their Climate Leader's normalized GHG reduction goal. See the Climate Leaders *Reporting Requirements* for more discussion on how this is done.

1.2. Utility Reporting of Purchased Electricity or Steam

Electric utilities, like other entities, may also need to purchase electricity or steam. This heat or power could be sold for resale, sold to end-users, or consumed at owned offices or through transmission and distribution losses. This guidance is for non-utilities only.

1.3. Emissions of CO_2 versus CH_4 and N_2O for Purchases/Sales of Electricity and Steam

Although CO_2, CH_4, and N_2O are all emitted during the combustion of fossil fuels to produce electricity, CO_2 accounts for the majority of all greenhouse gas emissions. In the U.S., CO_2 emissions represent over 99.6% of the total CO_2-equivalent[1] GHG emissions from fuels combusted for electricity production, with CH_4 and N_2O together representing less than 0.4% of the total emissions from the same sources[2].

1 See Chapter 6 of the *Climate Leaders Design Principles* document for a discussion of CO_2-equivalents.

2 Tables 3-3, 3-14, & 3-15 of *U.S. EPA 2007 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005*, EPA430-R-07-002.

As with direct emissions from stationary combustion sources, Partners should account for all CO_2, CH_4, and N_2O emissions associated with purchases of electricity and steam[3]. CO_2 emissions calculations are fairly straightforward while CH_4 and N_2O emissions are not as easy to characterize, as explained in Section 1.1 of the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*.

Given the relative emissions contributions of each gas, CH_4 and N_2O emissions are often excluded by assuming that they are not material. However, as outlined in Chapter 1 of the *Climate Leaders Design Principles*, 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 greenhouse gases. Therefore, this guidance provides information on estimating CO_2 as well as CH_4 and N_2O emissions from purchases of steam and/or electricity.

3 Emissions of SF_6 are associated with transport of electricity. However, SF_6 emissions are considered outside the scope of indirect emissions from electricity purchases. SF_6 emissions are reported as direct emissions for owners of transmission and distribution lines. It is also assumed that SF_6 emissions are not directly affected by the total amount of electricity transmitted.

Methods for Estimating Emissions

This section addresses the estimation of GHG emissions from purchased and sold electricity and steam. Both the purchase and sales of electricity and steam across Partner corporate boundaries should be accounted for using these methods. Since a variety of fuels may be used to generate electricity and steam, emission factors can vary greatly. The preferred method for estimating emissions is to use a source or facility-specific approach ("bottom-up" approach) e.g., first estimating the electricity purchases by facility then summing across facilities to get the Partner's total emissions. See Chapter 9 of the *Climate Leaders Design Principles* for more detail on reporting requirements.

Sections 2.1 through 2.3 present an overview of the different methods that can be used to calculate GHG emissions from electricity and steam purchases and sales. Emissions from cogeneration sources are outlined in Section 2.4.

2.1. Estimating Emissions from Purchased Electricity

For electricity purchases from the grid or through a direct contract, emissions are estimated by multiplying the purchased electricity by average emission rates. Equation 1 describes the approach for estimating emissions from purchased electricity.

The steps involved with estimating emissions from consumption of purchased electricity are shown below.

Step 1: Estimate amount of electricity purchased. Utility bills or other records should be used to provide the amount of purchased electricity.

Equation 1: Estimating GHG Emissions from Electricity Purchases

$$\text{Emissions}_i = \text{EP} \times \text{ERate}_i$$

where:

Emissions_i = Emissions of gas i (mass)

EP = Electricity purchased and consumed on-site (e.g., MWh)

ERate_i = Gas i emissions rate for electricity purchased $\left(\text{e.g., } \frac{\text{mass } CO_2}{\text{MWh}}, \frac{\text{mass } CH_4}{\text{MWh}}, \text{ or } \frac{\text{mass } N_2O}{\text{MWh}}\right)$

Step 2: Determine emission rates. The approach recommended by Climate Leaders is to calculate electricity use emissions based on average emission rates that best represent the electricity actually purchased. There are a number of published electricity production emission rates with varying degrees of accuracy as discussed in Section 3.2.1. Emission rates are typically provided in terms of mass per energy unit (e.g., kWh, MWh, Joules, etc.). If the Partner has emission rates obtained from a dedicated "over-the-fence" plant, they may use those emission rates instead of average published values. If the electricity is purchased from a co-generation facility, the emission rates should represent only the electricity produced at the facility, as described in Section 2.4.

Step 3: Estimate emissions. To estimate emissions, multiply purchased electricity (e.g., MWh) by the appropriate emission rate (e.g., mass CO_2/MWh).

2.2. Estimating Emissions from Purchased Steam

The preferred method for calculating emissions associated with steam purchases is to use emission factors obtained directly from the steam suppliers. However, if factors are not available, emissions can be calculated based on assumed boiler efficiency, fuel mix, and fuel emissions factors. Equation 2 describes the approach for estimating emissions from purchased steam based on factors provided by the supplier.

The steps involved with estimating emissions from consumption of purchased steam with the emission factor approach are shown below.

Step 1: Estimate amount of steam purchased. Utility bills or other records should be used to provide amount of purchased steam (in terms of energy, mass, or volume).

Equation 2: Estimating GHG Emissions from Steam Purchases Based on Factors

$$\text{Emissions}_i = SP \times \text{SRate}_i$$

where:

Emissions_i = Emissions of gas i (mass)

SP = Steam purchased and consumed on-site (energy, mass, or volume)

SRate_i = Gas i emissions rate for steam purchased

$$\left(\text{e.g., } \frac{\text{mass } CO_2}{\text{energy, mass, or volume}},\ \frac{\text{mass } CH_4}{\text{energy, mass, or volume}},\ \text{or } \frac{\text{mass } N_2O}{\text{energy, mass, or volume}}\right)$$

Step 2: Determine emission rates. In this case, emission rates are provided by the supplier in terms of mass per unit of energy, mass, or volume of steam depending on the units used in Step 1. If the steam is purchased from a co-generation facility, the emission rates should represent only the steam produced at the facility, as described in Section 2.4.

Step 3: Estimate CO_2 emissions. To estimate emissions, multiply steam purchases (energy, mass, or volume) by the appropriate emission factor (e.g., mass CO_2/ energy, mass, or volume).

If emissions factors are not specifically known for steam production, the emissions can be calculated based on assumed boiler efficiency, fuel mix, and fuel emissions factors. Equation 3 describes the approach for estimating emissions from purchased steam based on this approach.

The steps involved with estimating emissions from consumption of purchased steam with the boiler efficiency approach are shown below. If steam is purchased from a co-generation facility it is recommended that Partners use the previous approach, based on emission rates provided by the supplier.

Step 1: Estimate the amount of steam purchased. Utility bills or other records should be used to provide the quantity of purchased steam (in terms of energy). If records are provided as mass or volume (or dollars) they should be converted to energy content of the steam.

Step 2: Calculate fuel energy input to produce the steam. Divide the steam purchased (in energy units) by the assumed efficiency of typical steam production in a boiler to derive total fuel input needed (energy units). The steam supplier should be able to provide this efficiency. If no value is available, a default of 80% can be used.

Step 3: Determine the fuel mix used to produce the steam. Emission factors are dependent on the mix of fuel burned to generate purchased steam. The steam supplier

Equation 3: Estimating GHG Emissions from Steam Purchases Based on Efficiency

$$\text{Emissions}_i = \frac{SP}{BF} \times FSF_i$$

where:

Emissions_i = Emissions of gas i (mass)

SP = Steam purchased and consumed on-site (energy)

BF = Boiler efficiency $\left(\frac{\text{steam energy}}{\text{fuel energy}}\right)$

FSF_i = Gas i fuel specific factor $\left(\frac{\text{mass } CO_2}{\text{fuel energy}}, \frac{\text{mass } CH_4}{\text{fuel energy}}, \text{ or } \frac{\text{mass } N_2O}{\text{fuel energy}}\right)$

should supply fuel mix data, if possible. The fuel mix data can then be used to calculate the amount of energy used by fuel type.

Step 4: Estimate emissions. To estimate emissions from steam purchased, multiply fuel input by fuel type (in terms of energy) by the emission factors for that fuel, as per the methods described in the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*.

2.3. Estimating Emissions from Sales of Electricity and/or Steam

Emissions from the generation of electricity or steam that is sold off-site can be estimated by multiplying the amount of electricity or steam sold by an emission rate representative of the heat or power produced on-site. This emission rate can be calculated by dividing the total emissions from the generation of on-site electricity or steam (calculated based on methods described in the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*) by the total amount of electricity or steam produced. Equation 4 describes the approach for estimating emissions from sales of electricity or steam.

The following steps outline the approach to estimate emissions from electricity or steam sales. If the electricity or steam was produced in a co-generation facility, use the approach outlined in Section 2.4 to replace steps 1-4 below.

Step 1: Estimate amount of electricity or steam sold. An estimate of the amount of electricity or steam sold can be obtained from sales records or metering data.

Step 2: Estimate total emissions from the generation of electricity or steam. This is done for each of the on-site sources that produce electricity or steam for sale. The emissions are calculated based on the methods

Equation 4: Estimating GHG Emissions from Electricity or Steam Sales

$$\text{Emissions}_i = \text{Sales} \times \frac{TE_i}{\text{Prod}}$$

where:

Emissions_i = Emissions of gas i (mass)

Sales = Amount of electricity or steam sold (e.g., MWh, lbs. of steam, Btu's of steam)

TE_i = Gas i emissions from total facility production of electricity or steam (mass CO_2, CH_4, or N_2O)

Prod = Total amount of electricity or steam produced at facility (e.g., MWh, lbs. of steam, Btu's of steam) described in the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*.

Step 3: Determine the total amount of electricity or steam produced. Determine the total amount of electricity or steam produced from the on-site sources in Step 2. The total amount should correspond to the same time period as the emission calculations.

Step 4: Calculate emission rate for on-site electricity or steam production. Divide total emissions from on-site production by the total amount of electricity or steam produced on-site to get an emission rate (e.g., mass CO_2/MWh). This should be done for each of the different on-site sources that produce electricity or steam for sales.

Step 5: Estimate emissions associated with electricity sales. To estimate emissions from sales, multiply the amount of electricity or steam sold (Step 1) by the emission rates for the source from which it was produced (Step 4).

The total emissions from a Partner's electricity or steam production are reported to Climate Leaders as direct emissions. The portion of those direct emissions that are associated with electricity or steam sales (as determined from the above approach) can optionally be reported separately as supplementary information.

2.4. Allocating Emissions from a Co-Generation Facility to Separate Electricity and Steam Outputs

In a co-generation or combined heat and power (CHP) plant, electricity and steam are generated together from the same fuel supply. If a Partner is purchasing or selling all of the output from the CHP plant (or in the same proportions as they are generated) then an average emission rate is sufficient. An average emission rate is obtained by dividing the total emissions at the CHP plant by the total output of the plant (steam and electricity outputs have to be converted to the same units and combined).

However, if only part of the electricity or steam generated by the CHP facility is purchased or sold, allocating total emissions to the different generated energy streams (normally steam and electricity) is necessary.

There are several methods for allocating emissions from CHP production (e.g., heat output, financial, etc.) and there are certain advantages and disadvantages inherent to each approach[4]. It is important to have a consistent method used by both the producer and any number of purchasers of steam and electricity to insure accurate reporting of emissions and no double counting between multiple users of CHP output. The preferred method of allocating emissions between the steam and electricity output of a CHP plant is a contractual agreement between all parties. In the absence of this sort of agreement, the preferred Climate Leaders allocation method is the efficiency approach. The efficiency approach uses sepa-

4 For more description of the allocation methods available see the GHG calculation tool, *Calculating tool for direct emissions from stationary combustion*, Guidance section (Jul. 2005 v3.0) developed by the World Resources Institute. Available at www.ghgprotocol.org

rate efficiencies for heat and power production to allocate emissions between the two types of CHP output.

To determine the share of emissions attributable to both heat and power production using the efficiency approach, follow the steps below. An example of this method is given in Appendix A.

Step 1: Determine the total steam and electricity output and total emissions for the CHP system. The CHP system from which steam or electricity is either purchased or sold could have multiple steam or electricity outputs. For this allocation approach these different flows should be combined into two separate values, one for steam output, and one for electricity output. Furthermore, these flows should be in the same units of energy (e.g., all expressed as Btu's).

Note: Convert kWh of electricity to Btu using a factor of 3,412 Btu/kWh.

Steam tables provide energy content (enthalpy) values for steam at different temperature and pressure conditions. Enthalpy values multiplied by the quantity of steam give energy output values. The GHG emissions associated with total fuel input can be calculated based on the fuel mix of the CHP plant, and the methods described in the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*.

Step 2: Estimate the efficiencies of steam and electricity production. This method is based on the assumption that conversion of fuel energy to steam energy is more efficient than converting fuel to electricity (thermal efficiencies). The efficiencies are used to determine the amount of fuel input, and therefore emissions, associated with steam vs. electricity production. If actual efficiencies are not known, default values can be used as described in Appendix A.

Note: Use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. This is not a significant issue but users should be aware of energy balance. See Appendix A for more detail.

Step 3: Determine the fraction of total emissions to allocate to steam and electricity production. Equations 5 and 6, found on the next page, are used for this step.

Step 4: Calculate emission rates for steam and electricity production. Divide the total emissions from steam production (Step 3) by the total amount of steam produced to get an emission rate (e.g., mass CO_2/amount of steam). Divide the total emissions from electricity production (Step 3) by the total amount of electricity produced to get an emission rate (e.g., mass CO_2/amount of electricity).

Step 5: Estimate emissions from purchases or sales. To estimate emissions, multiply the amount of steam or electricity either purchased or sold by the appropriate emission rate (Step 4). Note: units used to report steam or electricity usage should be the same units used to calculate the emission rates.

Equation 5: Allocating Emissions to Steam Production from a CHP Plant

$$E_H = \frac{\frac{H}{e_H}}{\frac{H}{e_H} + \frac{P}{e_P}} \times E_T$$

where:

E_H = emissions allocated to steam production

H = steam output (energy)

P = delivered electricity generation (energy)

e_H = assumed efficiency of steam production

e_P = assumed efficiency of electricity generation

E_T = total emissions of the CHP system

- and -

Equation 6: Allocating Emissions to Electricity Production from a CHP Plant

$$E_P = E_T - E_H$$

where:

E_P = emissions allocated to electricity production

E_T = total emissions of the CHP system

E_H = emissions allocated to steam production (from Equation 5)

Choice of Activity Data and Emission Calculation Factors

This section discusses choices of activity data and factors used for calculating emissions from purchases and sales of electricity and steam. This guidance has been structured to accommodate a wide range of facilities with varying levels of available information.

3.1. Activity Data

For electricity purchases, utility bills are a good measure of electricity used. Typically this is reported as kWh or MWh. This information on the electricity entering a facility is considered the best type of activity data as opposed to sub-metering data which may be incomplete.

In some cases it may be difficult for a Partner to obtain utility bills or metering data for a site included in their inventory, for example, from leased office space. However, it is recommended that they try to obtain utility bills or metered data to calculate electricity use activity data.

Steam is physically measured in terms of pressure, temperature, and flow rate. This information can be used with standard steam tables to calculate the steam's energy value. Purchased steam, like purchased fuel, is typically reported in energy units to better reflect the use of the steam. Unlike fuel, the conversion of metered steam units to energy units is standardized and based on steam tables. It is recommended that steam purchasers record the quantity (mass), characteristics (temp and pressures), and total energy of the steam purchased.

In some cases, not all of the energy entering a facility as steam is used in the facility's processes. Some of the energy could be returned to the steam supplier as condensate. If this is the case, the returned energy should be reflected in a higher boiler efficiency or a lower steam emission rate. It takes less fuel energy to produce the same amount of steam if a high temperature condensate is used as input as opposed to make up water at a lower temperature.

For electricity and steam sales, it is preferred that data on emissions and the amount of electricity and steam generated and sold be obtained from each exporting generator or boiler, if possible. Otherwise, this data can be estimated at the facility level.

3.2. Emission Rates

Emission rates are necessary to calculate the emissions attributable to electricity and steam purchases. They should be chosen based on the guidance below. This guidance deals primarily with electricity and steam produced from sources other than CHP. Allocating emissions from a CHP plant involves applying factors other than emission rates. Default values for these factors are discussed in Appendix A.

3.2.1. Electricity Purchases

Activity data is used to determine the amount of electricity purchased. The amount of electricity actually generated to provide this purchased electricity is usually more that what is purchased due to transmission and distribution losses. On average in the U.S., nine percent of the total electrical energy input is lost in transmission and distribution[5]. It is the responsibility of the owner of the transmission lines to report on transmission and distribution losses. Therefore, Partners only report emissions associated with the amount of electricity they purchase and consume within their facilities. The emission rate for electricity generation depends on the method/type of fuel used and the efficiency of converting input energy into electricity. To some extent, electricity purchasers have the ability to control the environmental attributes of the electricity they purchase. A Partner may choose to purchase green or renewable energy as opposed to more conventional electricity generation based on the combustion of fossil fuels.

In states with competitive electricity markets, purchasers have the ability to choose their electricity supplier. Depending on the market, suppliers may offer electricity that contains a percentage of renewable or green power. In states without competitive electricity markets, purchasers also have the ability to purchase green power through block products or green power pricing[6]. With this method, purchasers pay a premium for a certain amount of green power which the electricity supplier then buys to be added to the grid[7]. Climate Leaders has developed a green power purchase guidance document, which is available at the Climate Leaders Web site, www.epa.gov/climateleaders.

Also, the emissions from electricity production vary by season and even time of day because different types of plants produce electricity for the grid at given times. Base-load plants operate continuously and provide a base level of electricity to the grid. Intermediate and peaking units come into operation when there is a spike or increased demand for electricity. Often the emissions associated with these two types of power are very different. An average electricity production rate includes all units generating electricity for the grid including baseload, intermediate, and peaking units.

Under Climate Leaders, Partners should use the emission rate that best represents the ***average*** emissions from the electricity generation used to supply the electricity that they purchase.

If a Partner purchases electricity directly from a known electric generation source, such as a dedicated “over-the-fence” plant or source that can be specifically identified, then emission rates from that plant may be used to estimate indirect emissions due to electricity purchases. Otherwise, Partners should use published emission factors based on each of their facility’s geographic location, corresponding to the average emissions rate of electric generators supplying power to the grid. Specifically, the Partner should use subregion grid factors published by the EPA’s Emission & Generation Resource Integrated Database (eGRID)[8]. An eGRID subregion represents a portion of the

5 Energy Information Administration, *Annual Energy Review 2006*, June 2007.

6 Another approach for companies to purchase green power is through the use of “Green Tags” or Renewable Energy Certificates (RECs). This involves purchasing just the environmental attributes associated with green power.

7 The grid is the network of transmission lines that is used to deliver power to end-users.

8 The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of all electric power generated in the United States. An integration of 23 different federal data sources, eGRID provides information on air pollutant emissions and resource mix for individual power plants, generating companies, states, and regions of the power grid. EGRID is available at http://www.epa.gov/clean energy/energy-resources/egrid/index.html.

U.S. power grid that is contained within a single North American Electric Reliability Council (NERC) region. Most of eGRID's subregions consist of one or more power control areas (PCAs). eGRID subregions generally represent sections of the power grid that have similar emissions and resource mix characteristics and may be partially isolated by transmission constraints. If a Partner does not know what eGRID subregion a facility is located in, they can use the Power Profiler Tool, available at www.epa.gov/cleanenergy/powerprofiler.html. This tool allows users to enter their facility zip code and utility name to obtain the associated eGRID subregion.

In cases where purchased electricity comes from both a dedicated "over-the-fence" plant and from the grid, the Partner should pro-rate the indirect emissions using a generator-specific emission factor for the portion of the power taken from the specific known source, and a grid average factor for the portion of the electricity consumption taken from the grid.

The approach described above is applicable for both CH_4 and N_2O as well as CO_2 emission rates. Some utilities may have emission rates available for CH_4 and N_2O emissions, which could be applied to estimate indirect emissions of these gases. However, eGRID does not specifically list emission rates for CH_4 and N_2O emissions from electricity production, only CO_2. Therefore, EPA has developed CH_4 and N_2O emission rates for the eGRID subregions based on the underlying fuel use data and fuel specific CH_4 and N_2O emission factors (from Section 3 and Appendix A of the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*). A map of the eGRID subregions and year 2004 CO_2, CH_4, and N_2O emission rates are provided in Appendix B. Partners should use the eGRID emission rates corresponding to the year of their inventory activity data. For example, a Partner's 2004 inventory should be based on 2004 eGRID emission rate data and their 2005 inventory should be based on 2005 eGRID emission rate data, if available. If eGRID emission rate data is not available for a certain year then the Partner should use the most recent eGRID emission rate data. In this example, if 2005 eGRID emission rate data were not available for the Partner's 2005 inventory then 2004 eGRID emission rates should be used. For all subsequent annual inventories the Partner should continue to use 2004 eGRID emission rate data until a new eGRID release. Partners are not expected to retroactively update their inventories with new eGRID factors once the inventory has been submitted to EPA.

eGRID emission rates may change between eGRID releases due to changes in resource mix characteristics or regional boundaries. Therefore, a Partner's GHG emissions from indirect electrical purchases may change due to a change in eGRID emission rates, irrespective of the Partner's electricity consumption. If a Partner believes that future changes in eGRID emission rates may materially affect the achievement of its GHG reduction goal, the Partner may request that EPA approve a different procedure for incorporating eGRID factors into its GHG inventory. This procedure should be specified in the Partner's base year IMP and be followed throughout the Partner's goal period.

3.2.2. Steam Purchases

Emissions associated with the production of steam are highly dependent on the type of fuel burned. Since purchased steam is produced very close to the facility (due to the difficulties associated with transporting steam over long distances), it should be possible to determine the source of the steam and which fuels were combusted for its production. Therefore, type of fuels used and appropriate emission factors should be obtained directly from the steam suppliers. If this data is not available, a Partner may use the fuel types and boiler efficiencies to calculate emissions. In this case, default values of 80% boiler efficiency and natural gas fuel can be assumed.

Completeness

In order for a Partner's GHG corporate inventory to be complete it must include all emission sources within the company's chosen inventory boundaries. See Chapter 3 of the *Climate Leaders Design Principles* for detailed guidance on setting organizational boundaries and Chapter 4 of the Climate Leaders Design Principles for detailed guidance on setting operational boundaries of the corporate inventory.

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

At the operational level, a Partner should include all GHG emissions from the sources included in their corporate inventory. Possible GHG emission sources are stationary fuel combustion, combustion of fuels in mobile sources, purchases of electricity, HFC emissions from air conditioning equipment and process or fugitive related emissions. Partners should refer to this guidance document for calculating indirect emissions from electricity/steam purchases and to the Climate Leaders Core Guidance documents for calculating emissions from other sources. The completeness of facility level data can be checked by comparing the facility energy bills against accounting records of expenditures for electricity and steam.

As described in Chapter 1 of the *Climate Leaders Design Principles*, 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.

The inventory should also accurately reflect the timeframe of the report. In the case of Climate Leaders, the emissions inventory is reported annually and should represent a full year of emissions data.

Leased Space: A Partner's indirect emissions from leased spaces are based on the organizational boundary approach selected by the Partner to determine their corporate GHG inventory. For example, in the case of leased spaces under the operation control approach, the Partner is generally responsible only for the spaces for which they have access to the data (i.e., spaces for which they pay the utility bills). However, a Partner may choose to include electricity usage from leased spaces defined as optional sources, in order to provide a more complete picture of their company overall climate change impact. In this case, a Partner's electricity usage may be apportioned based on their leased floor space, the total building floor space and the total building electricity usage.

Uncertainty Assessment

There is some level of uncertainty associated with all methods of calculating GHG emissions from purchases of steam and electricity. As outlined in Chapter 7 of the *Climate Leaders Design Principles*, Climate Leaders does not recommend Partners quantify uncertainty as +/- % of emissions estimates or as data quality indicators. The effort spent performing such analysis is better spent pursuing high quality inventory data. It is recommended that Partners attempt to identify the areas of most uncertainty in their emissions estimates and consider options for improving the quality of this data in the future.

The accuracy of estimating emissions from purchases of steam or electricity is partially determined by the availability of data concerning the quantity of electricity or steam purchased. For example, if the amount of electricity or steam purchased is taken directly from utility bills, then the resulting uncertainty should be fairly low. However, electricity use based on adding sub-meter data may not be as accurate as fuel bills because it may be difficult to meter every source of electricity use (e.g., lighting).

The accuracy of estimating emissions from purchased electricity and steam is also determined by the emission rates used to convert purchases into indirect emissions. Rates for purchased steam should be fairly accurate if specific data on the source of the steam is known. However, average grid emission rates must be used with many electricity purchases because it is difficult to trace electricity purchases from the grid to the actual electricity production sources. These average emission rates are not completely accurate because the rates vary by time of day and season based on what units are operating (e.g., base load vs. peaking load). Published average rates are even more uncertain especially if the data is calculated for a year that differs from the year of purchase. If using emission rates from eGRID, keep in mind that data may be out of date. EPA recommends Partners choose the most accurate emission rate representing their purchased electricity. This includes using emission rates that coincide with the year of electricity use, if available, and updating their inventory as more recent emission rates become available.

Partners should be as transparent as possible when reporting historical activity data (amount of electricity or steam purchased or sold) so that emission rates may be changed at a future date if more accurate emission rates become available.

Reporting and Documentation

Partners are required to complete the Climate Leaders *Reporting Requirements* for purchases/sales of electricity and steam and report annual corporate level emissions. In order to ensure that estimates 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 data, and should be reported in the Partner's Inventory Management Plan (IMP).

Table 1: Documentation Sources for Mobile Combustion

Data	Documentation Source
Amount of electricity and steam purchased	Meter records, purchase receipts, contract purchase or firm purchase records
Amount of electricity and steam sold	Meter records, delivery or sales receipts, contract or firm records
Prices used to convert dollars or electricity and steam to amount (kWh or Btu)	Purchase receipts; delivery or sales receipts; contract purchase or firm purchase records; EIA, EPA, or industry reports
Any assumptions made	All applicable sources

Inventory Quality Assurance and Quality Control (QA/QC)

Chapter 7 of the *Climate Leaders Design Principles* provides general guidelines for implementing a QA/QC process for all emission estimates. For indirect electricity and steam emissions, activity data and emission rates can be verified using a variety of approaches:

- An energy audit could be performed at the facility to determine all sources that use electricity. Results can be compared to electricity bills to verify use.
- Electricity bills can also be compared to actual meter readings to verify they are accurate representations and not estimates.
- Data on electricity or steam use can be compared with data provided to the Department of Energy or other EPA reports or surveys.
- If a Partner accounts for electricity or steam exports, stationary combustion guidelines should be followed to estimate emissions.
- If sub-meter data on electricity use is the basis for determining electricity use, then care should be taken to insure that the sum of the sub-meters represents the full electricity demand of the facility.
- Emission rates provided by electricity or steam providers should be checked against published rates and any major discrepancies should be explained.
- Use of electricity or steam generated on-site should not be accounted for in indirect emissions calculations. The emissions from on-site electricity and steam production are accounted for under direct emissions.

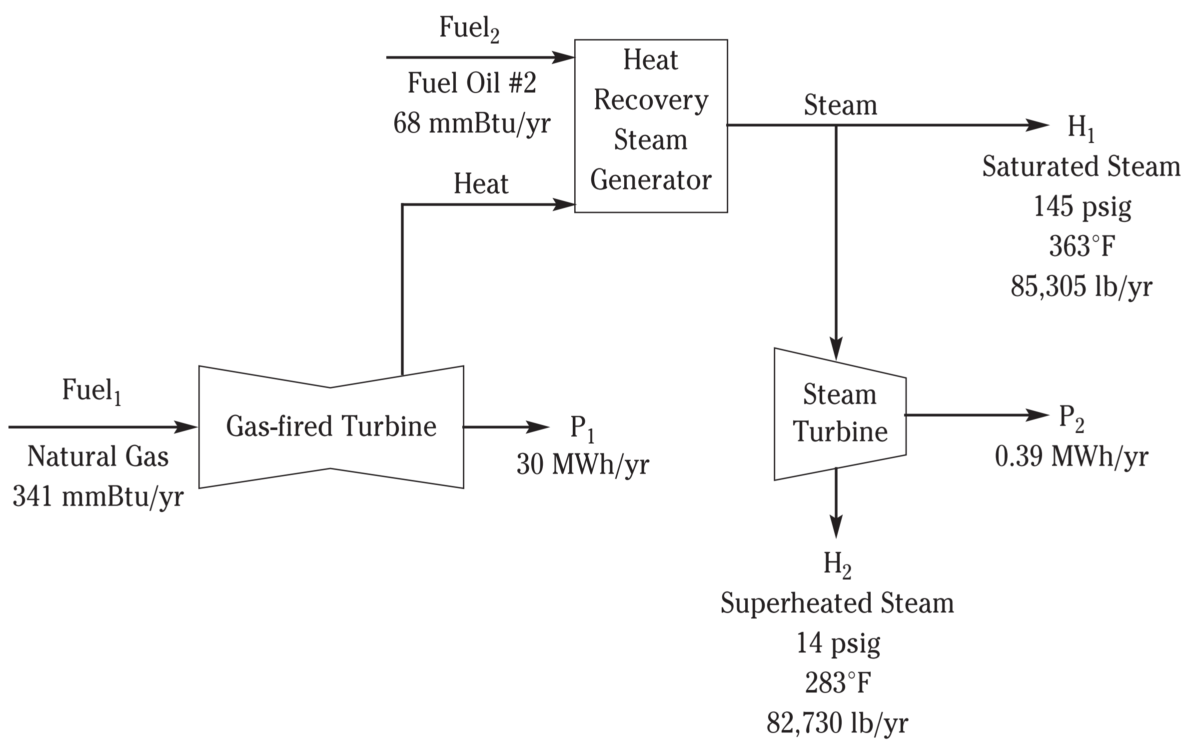
Example of Co-Generation Allocation Methods

Figure A-1 presents an example flow diagram of a gas-fired turbine combined cycle (GTCC) CHP system that incorporates a heat recovery steam generator (HRSG) with supplemental fuel firing. This CHP system includes four energy output streams (two steam streams, H_1 and H_2, and two power outputs, P_1 and P_2) and incorporates two fuel inputs (one to the gas-fired turbine and a second to the HRSG). It can be assumed that the power (P_1 and P_2) and heat outputs (H_1 and H_2) are well characterized (energy content is known). The fuel inputs to the CHP system ($Fuel_1$ and $Fuel_2$) are also known.

The efficiency allocation method described in this guidance is applied to the above example and the related CO_2 emission factors for the different output streams are calculated. The same approach is used to calculate CH_4 and N_2O emission factors, however, only the calculation for CO_2 is shown here.

Note: All calculations are done on a yearly basis.

Figure A-1: Gas-fired Turbine Combined Cycle CHP System



Step 1: Convert steam output flows into units of energy using steam tables and quantity of steam produced. Then combine all steam outputs, and electricity outputs into one value for each and express the values in the same units.

H_1 = 1,196 Btu/lb. (from steam tables) × 85,305 lb. = 102 mmBtu

H_2 = 1,180 Btu/lb. (from steam tables) × 82,730 lb. = 97.6 mmBtu

H = 102 mmBtu + 97.6 mmBtu = 200 mmBtu

P = (30 MWh + 0.39 MWh) × 3.412 mmBtu/MWh = 104 mmBtu

Convert energy input into CO_2 emissions using the Climate Leaders guidance for *Direct Emissions from Stationary Combustion Sources*.

Natural Gas emissions = 341 mmBtu × 14.47 kg C/mmBtu × 0.995 × (44/12) = 18,002 kg CO_2 or 18 metric tons CO_2

Fuel Oil # 2 emissions = 68 mmBtu × 19.95 kg C/mmBtu × 0.99 × (44/12) = 4,924 kg CO_2 or 4.9 metric tons CO_2

Total CO_2 emissions = 18 metric tons CO_2 + 4.9 metric tons CO_2 = 22.9 metric tons CO_2

Step 2: Estimate the efficiencies of steam and electricity production. Assume Climate Leaders default values of:

e_H = 80% and e_P = 35%

It may be helpful to ensure that use of these default efficiency values do not violate the constraints imposed on the system by the energy balance. This can be checked by comparing the calculated assumed energy input with the actual energy input of the CHP plant. Assumed energy input is calculated based on the heat and power output and the assumed efficiencies as shown in the following equation

$$\text{Assumed Energy Input} = \frac{H}{e_H} + \frac{P}{e_P}$$

In this example:

$$\frac{200 \text{ mmBtu steam}}{0.8 \text{ mmBtu steam/mmBtu fuel}} + \frac{104 \text{ mmBtu power}}{0.35 \text{ mmBtu power/mmBtu fuel}} = 547 \text{ mmBtu fuel}$$

The energy balance constraint has been violated because 547 mmBtu is more than the fuel consumption of the CHP system (409 mmBtu). This is not a significant issue, since total emissions are still allocated between the energy outputs. However, the user should be aware of the energy balance and if the constraints are not satisfied e_H and e_P can be modified until constrains are met. In this example, violation of the energy balance constraint is not considered significant and the default factors e_H and e_P are not modified.

Step 3: Determine fraction of total CO_2 emissions to allocate to steam and electricity.

E_H = {(200 / 0.80) / [(200 / 0.80) + (104 / 0.35)]} × 22.9 = 10.5 metric tons CO_2

E_P = 22.9 - 10.5 = 12.4 metric tons CO_2

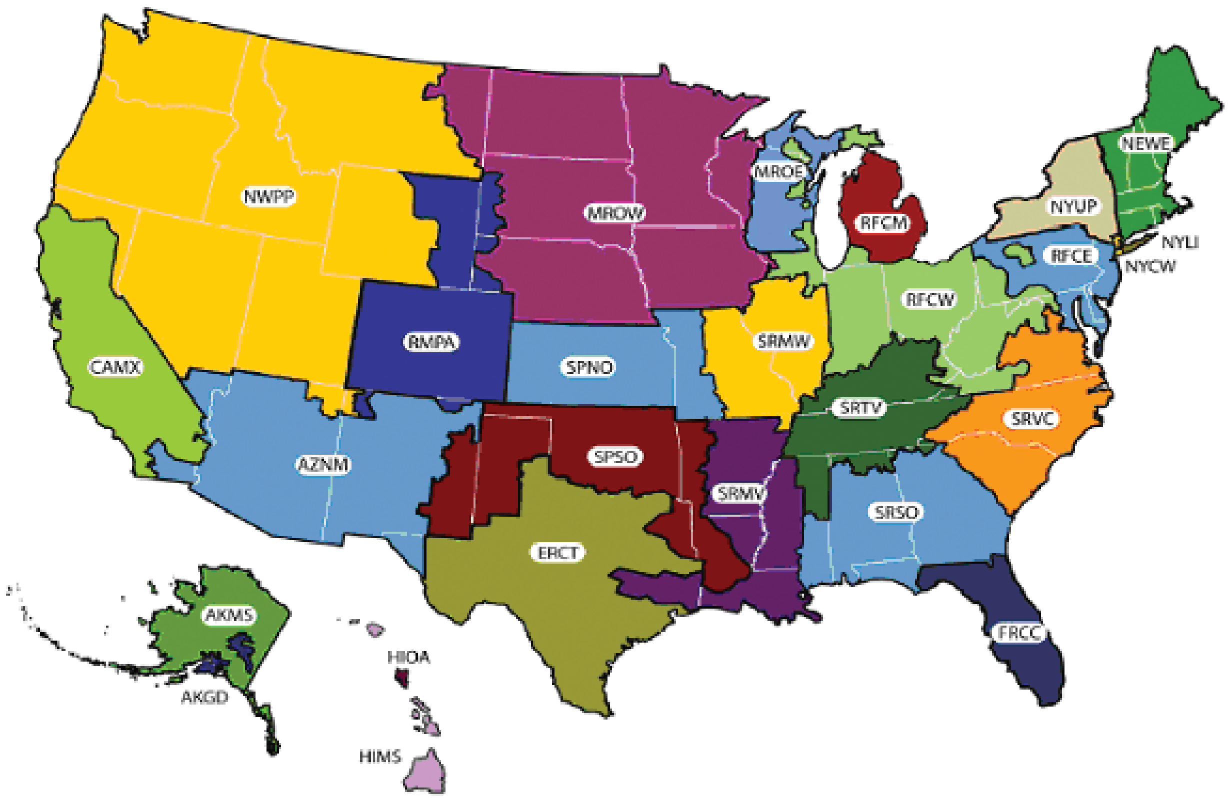
Step 4: Calculate CO_2 emission factors for steam and electricity production.

For steam: 10.5 metric tons CO_2 / 200 mmBtu =
0.052 metric tons of CO_2 per mmBtu of steam produced

For electricity: 12.4 metric tons CO_2 / 104 mmBtu =
0.120 metric tons of CO_2 per mmBtu of electricity produced

Steps 1-4 are repeated to calculate CH_4 and N_2O factors as well.

eGRID Subregion Emission Rates



Name	Abbr.	Year 2004 Emission Rates		
		(lbs CO_2/MWh)	(lbs CH_4/MWh)	(lbs N_2O/MWh)
ASCC Alaska Grid	AKGD	1,257.19	0.0266	0.0064
ASCC Miscellaneous	AKMS	480.10	0.0238	0.0044
WECC Southwest	AZNM	1,254.02	0.0175	0.0148
WECC California	CAMX	878.71	0.0366	0.0085
ERCOT All	ERCT	1,420.56	0.0214	0.0148
FRCC All	FRCC	1,327.66	0.0528	0.0150
HICC Miscellaneous	HIMS	1,456.17	0.0999	0.0182
HICC Oahu	HIOA	1,728.12	0.0911	0.0212
MRO East	MROE	1,858.72	0.0314	0.0289

Table continued on page 22

Table continued from page 21

Name	Abbr.	Year 2004 Emission Rates		
		(lbs CO_2/MWh)	(lbs CH_4/MWh)	(lbs N_2O/MWh)
MRO West	MROW	1,813.81	0.0264	0.0287
NPCC New England	NEWE	908.90	0.0795	0.0152
WECC Northwest	NWPP	921.10	0.0217	0.0140
NPCC NYC/Westchester	NYCW	922.22	0.0384	0.0060
NPCC Long Island	NYLI	1,412.20	0.0684	0.0117
NPCC Upstate NY	NYUP	819.68	0.0242	0.0114
RFC East	RFCE	1,095.53	0.0244	0.0168
RFC Michigan	RFCM	1,641.41	0.0340	0.0253
RFC West	RFCW	1,556.39	0.0196	0.0244
WECC Rockies	RMPA	2,035.81	0.0241	0.0302
SPP North	SPNO	1,971.42	0.0236	0.0303
SPP South	SPSO	1,761.14	0.0301	0.0230
SERC Mississippi Valley	SRMV	1,135.46	0.0413	0.0132
SERC Midwest	SRMW	1,844.34	0.0214	0.0288
SERC South	SRSO	1,490.37	0.0388	0.0248
SERC Tennessee Valley	SRTV	1,494.89	0.0233	0.0237
SERC Virginia/Carolina	SRVC	1,146.39	0.0291	0.0191
Total US		**1,363.00**	**0.0298**	**0.0196**

Note: CH_4 and N_2O factors are based on the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005*, EPA 430-R-07-002, Washington, DC, April 2007 (Annex 3, Table A-69).

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