Power Generation/Electric Utility Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions
Produced by Electric Power Generators
and Electric Utilities

Version 1.1

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Abbreviations and Acronyms

API	American Petroleum Institute
C	carbon
CARROT	Climate Action Registry Reporting Online Tool
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring Systems
CH_4	methane
CO_2	carbon dioxide
DOE	U.S. Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration (U.S. DOE)
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG(s)	greenhouse gas(es)
GRP	General Reporting Protocol
GWP	Global Warming Potential
HFC	hydrofluorocarbon
kWh	kilowatt-hour
lb	pound
MMBtu	million British thermal units
MWh	Megawatt-hour
N_2O	nitrous oxide
NERC	North American Electric Reliability Council
PFC	perfluorocarbon
PUP	Power/Utility Protocol
California Registry	The California Climate Action Registry
SEC	Securities & Exchange Commission
SF_6	sulfur hexafluoride
T&D	transmission and distribution
WRI	World Resources Institute

1 Introduction

This document, the Power Generation/Electric Utility Reporting Protocol (Power/Utility Protocol or PUP), is an appendix to the California Climate Action Registry's (California Registry) General Reporting Protocol (GRP). It provides reporting standards for how electric power generation and utility (electricity transmission and distribution) entities must compile, report, and verify their entity-wide GHG emissions to submit their annual emissions inventory to the California Registry.

Many electric utilities also have natural gas operations, including natural gas storage, transmission and distribution. This protocol does not contain guidance for reporting the emissions from natural gas operations of electric utilities. California Registry suggests following industry best practice guidance to calculate and report these emissions.

The GRP provides the framework for businesses, government agencies, and non-profit organizations to participate in the California Registry. It presents the principles, approach, methodology, and procedures required for effective participation in the California Registry. The GRP is designed to support the complete, transparent, and accurate reporting of an organization's greenhouse gas (GHG) emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions in a quantifiable manner.

The GRP guides participants through the California Registry's reporting rules, emissions calculation methodologies, and the Climate Action Registry Reporting Online Tool (CARROT). By joining the California Registry, participants agree to report their GHG emissions according to the guidelines in the GRP and its appendices.

Additional guidance is also provided for some industries that require additional clarification to report their California or U.S. emissions in a comparable, consistent, and accurate manner. Thus, the California Registry has developed the Power/Utility Protocol for companies that generate or transmit electricity.

The GRP assumes the following. These assumptions are also true for this PUP:

- Participants are encouraged to report all six GHGs starting in year one, but may opt to limit their reports to only carbon dioxide (CO_2) emissions during the first three years of participation in the California Registry. After the third year of California Registry participation, participants are required to include all six GHGs (if applicable) in their annual emissions report.
- Heat values are calculated using Higher Heating Values (HHV).
- Global Warming Potential is calculated using factors from the Intergovernmental Panel on Climate Change's Second Assessment Report (1996), consistent with international practice. Values from the Third Assessment Report (2001) are also provided for comparison.
- Participants may designate up to 5% of their total emissions as de minimis.

1.1 Eligibility

Use of the PUP is required for entities in the electric power and utility sectors when reporting entity-wide GHG emissions to the California Registry. Power and utility entities are defined as those companies or facilities with the following root code in the North American Industry Classification System (NAICS):[1]

[1] http://www.census.gov/epcd/www/naics.html

2211 Electric Power Generation, Transmission and Distribution: This industry group is comprised of establishments primarily engaged in generating, transmitting, and/or distributing electric power. Establishments in this industry group may perform one or more of the following activities: 1) operate generation facilities that produce electric energy, 2) operate transmission systems that convey the electricity from the generation facility to the distribution system, and 3) operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer.

1.2 Industries that Generate Power/Steam/Heat

Because numerous industrial sectors generate electricity, heat or steam for their own use and even for sale to outside entities, portions of the PUP should serve as a reference for quantifying emissions associated with these activities. For example, the section of the protocol that addresses direct combustion emissions associated with combined heat and power (CHP) operations may apply to numerous industries outside of the power utility industry that operate CHP.

2 Defining Organizational Boundaries

This section discusses the options and requirements for determining your organizational boundaries. This includes guidance for what you must report in your GHG emissions report based on your ownership of different facilities.

2.1 Types of Organizational Relationships in Power/Utility Sectors

The electric power and utility sectors have a multitude of ownership and management control arrangements for power generation facilities, transmission & distribution assets for electricity and natural gas, as well as for the commodities themselves (electricity, steam, heat, and natural gas). These ownership scenarios are listed below:

1. *Full ownership* – There is one single owner of the asset
2. *Co-ownership* –There is more than one owner of the asset with varying degrees of ownership and operational control (ranging from 1% to 99%)
3. *Majority owner and operational control of the facility* – In some cases, the operator of the assets has control of the facility
4. *Minority owner but operational control of the facility* – In some cases, the operator of an asset may not have majority ownership of the facility
5. *Operator of the facility, but no ownership share* – In some cases, an entity has operational control without any ownership share
6. *Leasing* – The asset is leased for a discrete duration of time, with operational control resting with the lease holder
7. *Joint Power Agreement* – There is more than one public agency owner of the asset with varying degrees of ownership and operational control (ranging from greater than zero to less than 100%)

When determining your organizational boundaries, you may report using either management control and/or equity share. Because of the number of joint ownership arrangements common in power generation, it is strongly recommended that you calculate and report your GHG emissions using the equity share method. Whichever method you choose, you must report using the same method for every facility.

2.2 Equity Share

When reporting using equity share, you document only your company's economic interest in an operation. Your equity share will usually be the same as your ownership percentage.[2]

In the electric power and utility sector, joint ownership of assets is commonplace. To clarify ownership (rights) and responsibilities (obligations), companies involved in joint operations draw up contracts specifying the distribution of ownership between the parties. Where such arrangements exist, companies each report their emissions according to ownership arrangements described in the contracts.

2.3 Management Control

Under the management control approach, a company accounts for 100% of the GHG emissions from operations over which it has control. You should refer to the GRP if you have any questions as to whether or not you can establish management control.

If you choose to report using the management control method, you must also provide documentation from any partners with whom you share ownership in a facility, acknowledging who will be reporting the emissions from that facility.

Table 2.1 demonstrates how emissions would be reported under the different ownership scenarios using equity share and/or management control approaches.

Table 2.1. Reporting emissions under Equity Share and Management Control approaches.

	Equity Share	**Management Control**
Full ownership	100%	100%
Co-ownership	1-99% (based on ownership share)	If >50%: 100% If < 50%: 0
Majority owner and operational control of the facility	>50% based on ownership share	100%
Minority owner but operational control of the facility	<50% based on ownership share	0
Operator of the facility, but no ownership share	0	100%
Leasing	100%	100%
Joint Power Agreement	Varies with ownership share	If operational control or ownership >50%: 100% emissions If no operational control or ownership <50%: 0

3 Defining Operational Boundaries

This section provides guidance on determining which direct and indirect GHG emissions you must report to the California Registry. You must report all significant California or U.S. direct and indirect emissions.

[2] Language from the WRI/ WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition). http://www.ghgprotocol.org/standard/index.htm

3.1 Direct Emissions

Within the power/utility sectors, direct emissions come from:

- Stationary combustion from the onsite production of heat, steam, or electricity owned or controlled by your organization
- Fugitive leaks from operations owned or controlled by your organization
- Processes such as venting or emission control technologies and other activities that are owned or controlled by your organization
- Mobile combustion from non-fixed sources that are owned or controlled by your organization

This protocol provides guidance for you to calculate and report direct emissions from:

1. Stationary combustion
2. Fugitive emissions from electricity transmissions & distribution
3. Process emissions from SO_2 scrubbers

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct emissions from:

- Mobile combustion
- Fugitive emissions from air conditioning and refrigeration systems
- Fugitive emissions from fire suppression equipment

3.2 Indirect Emissions

Indirect emissions occur because of your actions, but are produced by sources owned or controlled by another entity. Indirect emissions come from:

1. Electricity, steam, and heating and cooling purchased and consumed. These include emissions from the generation of purchased energy that is consumed in equipment owned or controlled by your organization.
2. Transmission and distribution (T&D) losses:
    a. The portion of electricity purchased by your organization that is consumed during its transmission and distribution to end-use customers through equipment and infrastructure that is owned or controlled by your organization.
    b. The portion of wheeled electricity that is consumed by transmission and distribution equipment and infrastructure that is owned or controlled by your organization.
    c. The portion of electricity consumed during its transmission and distribution to direct access customers.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting indirect emissions from:

- Electricity use
- Electricity or steam purchased from co-generation
- Imported steam
- District heating and cooling

Example 3.1. Defining Operational Boundaries: An Electric Utility Company

An electric utility company operating in California owns electric generating facilities, an electric transmission and distribution system, and a natural gas transmission and distribution system. The company generates electricity and also purchases it from other generators to supply customers in California. The company also has office buildings and a fleet of vehicles that it uses in its business operations.

This electric utility company's entity-wide GHG inventory will include the following direct and indirect emission sources:
- Stationary combustion
- Mobile combustion
- Process emissions
- Fugitive emissions
- Indirect emissions from energy imported and consumed at office buildings
- Indirect emissions from T&D losses

3.3 Establishing and Updating a Baseline

All California Registry participants are encouraged to establish a baseline and adjust it over time when your organization undergoes structural changes. Chapter 4 of the GRP walks you through the options and process of selecting and establishing your baseline. For power/utility entities, the GRP provides all guidance needed to establish a baseline.

4 Geographic Boundaries

This section discusses requirements for determining the geographic boundaries of your GHG emissions report.

4.1 Determining Geographic Boundaries

You have the option of defining the reporting scope of your GHG inventory in two ways:
1. All GHG emissions in California (California reporting)
2. All GHG emissions in the U.S. – separated into California and non-California inventories (U.S. reporting)

The California Registry does not currently accept verifications of GHG emissions data from operations outside the U.S. However, you are encouraged to gather and retain this data for reporting to the California Registry in subsequent years. You may currently report international emissions optionally in CARROT, but this data will not be accepted into the public database.

Emissions are calculated based on where you generate, transmit or distribute electricity. If you own electricity generation inside and outside of California, your total reported direct emissions may change, depending on whether you report your U.S. or your California emissions.

4.2 U.S. Reporting

To determine your U.S. direct emissions, follow the steps in Sections 5-7 to calculate your total emissions from stationary combustion, power/utility processes, and fugitive sources for all facilities located in the U.S. Follow the steps in the GRP to calculate your total direct emissions from mobile combustion.

To determine your U.S. indirect emissions, follow the steps in Section 8 to calculate your total indirect emissions associated with energy purchased and consumed within the United States.

4.3 Reporting California Emissions

To determine your California direct emissions, you must calculate the emissions associated with electricity generated at any stationary combustion plant you own that is located inside the borders of the state of California. For generation stations physically located in the state, this includes all of the direct emissions associated with these facilities. You do not need to report any emissions from your out-of-state plants as part of your California-only inventory.

Note that information on the emissions from fossil fuel combusted at all of your plants to generate electricity delivered to California customers is required to calculate the required efficiency metrics. For more information, see Section 9: Industry-Specific Efficiency Metrics.

For transparency, you must also report the portion of your direct emissions associated with electricity from California plants delivered out of state.

To determine your California indirect emissions, you must calculate the emissions associated with energy purchased and consumed within the state of California. Emissions associated with electricity purchased and delivered to end-users in California should be included in the calculation of your California-only indirect emissions, regardless of where the power is generated.

Example 4.1 illustrates how your reported direct and indirect emissions may change, depending on whether you choose to report your California or your U.S. emissions.

Information on calculating direct emissions is provided in Section 5: Direct Emissions from Stationary Combustion.

Example 4.1. Determining Geographic Boundaries: An Electric Generation, Transmission and Distribution Company with facilities in California and Nevada

AB Power owns three electric generation facilities in California, two generating plants located in Nevada, and also has a transmission and distribution system through which it delivers electricity to customers in California.

The electricity that AB Power delivers to its customers comes from the company's own facilities located in California, its power plants located in Nevada, from power purchases from other generators located in Oregon, and from spot market purchases.

Reporting U.S. emissions

When reporting all U.S. emissions, AB Power calculates all fugitive, process, mobile and stationary combustion emissions associated with its facilities in California and Nevada and reports these as direct emissions. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions.

Reporting California emissions

When reporting California emissions only, AB Power calculates all direct emissions, including fugitive, process, mobile and stationary combustion, of its facilities in California. AB Power does not report any emissions from its Nevada plants. All emissions associated with electricity purchased from Oregon generators and consumed by AB Power through T&D or other activities are reported as indirect emissions. All emissions associated with electricity purchased from the spot market and consumed by AB Power through T&D or other activities are also reported as indirect emissions.

4.4 Geographic Boundaries vs. Organizational Boundaries

Your geographic boundary is not the same as your organizational boundary. Organizational boundaries reflect financial, legal, and operational relationships. Geographic boundaries reflect the physical location of your facilities. If you have facilities located both inside and outside of California, reporting according to geographic boundaries may not capture all of your organization's emissions. Thus, we strongly recommend that organizations with operations inside and outside of California report their U.S. emissions.

4.5 Level of Detail in Reporting

As stated in the General Reporting Protocol, you must report, at a minimum, your California direct and indirect emissions in the appropriate categories. All data is reported through CARROT. However, the California Registry recommends that you report your GHG emissions information at a sub-entity (i.e. business unit or facility) level. Reporting to this level of detail in CARROT will help to insure accuracy of your calculations, provide transparency and standardization, and thus help to lower your total costs of verification.

In addition to reporting in CARROT, you must also report your emissions and disclose a breakdown of your power generation and purchases (power purchased for the express purpose of meeting a load-based demand), if any, in the PUP Report. The PUP Report was created by the California Registry and must be uploaded as a publicly available attachment to the CARROT report. For additional guidance on completing the PUP Report, see the Instructions Tab included in the report workbook. Both the CARROT and PUP Reports will need to be verified by a third-party verification body.

5 Direct Emissions from Stationary Combustion

This section provides guidance on quantifying direct emissions from stationary combustion in the power/utility sector, including electric power generation, steam generation, auxiliary equipment, flaring and other related activities involving the combustion of fossil fuels or biomass fuels. You may need information on your reporting under 40 CFR Part 75, total annual fuel use broken down by fuel type, electricity production, steam production, and monitoring equipment information.

Power/utility companies that own or operate large combustion facilities may burn any combination of the following fuels: coal, oil, natural gas, biomass, or others for the production of electricity and/or heat and steam. Although hydrocarbon fuel combustion emits CO_2, CH_4, and N_2O, the CO_2 emissions associated with stationary combustion facilities will likely make up the largest percentage of your California or U.S. GHG inventory.[3]

The amount of CO_2 emitted from hydrocarbon combustion predominantly depends on the quantity of the fuel and carbon content of fuel consumed. To a lesser extent, the oxidation fraction of a particular fuel, under standard operating conditions and practices, also influences CO_2 emissions. (An oxidation fraction reflects an incomplete combustion process, to the extent that all the carbon contained in the fuel does not oxidize into CO_2 but remains as ash or unburned carbon.)

Non-fossil carbon bearing fuels (e.g. landfill gas, wood and wood waste, etc.) may also be combusted in stationary sources in the power/utility sector. International consensus on the net

[3] This is because during the combustion process, nearly all the carbon contained in hydrocarbon fuels is converted to CO_2, regardless of the fuel type or combustion configuration.

impact on climate from the combustion of biofuels has not yet been reached. You should not report biogenic CO_2 emissions as GHG emissions. However, it is important to identify the contribution of these emissions as a part of your overall activities. Thus, you must identify and report biomass CO_2 emissions as “biogenic emissions,” in a category separate from fossil fuel emissions. Note that CH_4 and N_2O emissions from the combustion of biomass are not considered biogenic and should be calculated and reported as part of your direct emissions inventory. For transparency, in CARROT biogenic emissions may be reported in the Optionally Reported category. Power/utility companies must, however, separately disclose power generation and purchases, as well as the corresponding CO_2 emissions, from biogenic sources in the PUP Report.

5.1 Stationary Combustion Equipment

The power/utility sectors use a number of stationary combustion technologies to generate, transmit, and distribute electricity and produce heat and/or steam. Power/utility companies also combust natural gas and other fossil fuels to transport, store, and distribute natural gas. Table 5.1 below lists examples of stationary combustion equipment that directly emit GHGs.

Table 5.1. Stationary combustion equipment.

Technology Category	Source Type
Boilers	Natural gas boilers, residual or distillate oil boilers, coal-fired boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.), biomass fired boilers, dual-fuel-fired boilers, and auxiliary boilers
Turbines	Combined cycle gas, simple cycle gas, combined heat and power, microturbines, steam turbines, and integrated gasification combined cycle
Internal Combustion Engines	Emergency and backup generators, reciprocating engines, compressors, firewater pumps, and black start engines
Flares	Natural gas, landfill gas, and waste gas
Other	Fuel cells, anaerobic digesters, and refuse-derived fuels

5.2 GHG Emissions Quantification Methods

To quantify CO_2 emissions from stationary combustion sources, power/utility companies must use one or both of the following two methods:

1. Measurement-based methodology
2. Fuel use calculation-based methodology

For most power/utility companies, the information needed to quantify and report direct stationary combustion GHG emissions to the California Registry should be available or easily derived from existing reporting activities. For major stationary sources, most power/utility companies already account for and report air pollution emissions to local, state and/or federal regulatory agencies, as well as total annual fuel use, and electricity, steam and heat production.[4]

Most large electric generating units have continuous emissions monitoring systems (CEMS) that track their CO_2 emissions. Smaller units, however, have not installed these monitors, but rely on fuel use data to determine their emissions. Because of these varying requirements, you may

[4] 40 CFR Part 75 provides all the protocols and procedures for operating continuous emissions monitors and quantifying and reporting air pollution and CO_2 emissions to the U.S. EPA. U.S. EPA Clean Air Markets Division - Consolidated Part 72 and 75 Regulations http://www.epa.gov/airmarkt/emissions/consolidated.html

have to use both the measurement-based and the calculation-based methodologies to report to the California Registry.

To maintain consistency with other programs, entities that are required to report emissions to the U.S. EPA according to 40 CFR Part 75 and/or state or local environmental agencies are strongly encouraged to report the same CO_2 emissions information to the California Registry.

Whichever method or combination of methods are used to calculate your GHG emissions inventory, you should use the same reporting methodology from year to year to maintain consistency and comparability between inventory years.

5.2.1 Measurement-Based Methodology

Continuous emissions monitoring systems (CEMS) are the primary emissions monitoring method used in the power/utility sector. The 40 CFR Part 75 rule includes requirements for installing, verifying, operating, and maintaining CEMS for measuring and reporting SO_2, NOx, CO_2, O_2, opacity, and volumetric flow.[5] The Part 75 rule also includes requirements for measuring and reporting emissions when CEMS are not utilized.

You may use either of the following two CEMS configurations to determine annual CO_2 emissions:

1. CO_2 CEMS and a Flow Monitoring System that measure CO_2 concentration, volumetric gas flow, and CO_2 mass emissions
2. O_2 CEMS and a Flow Monitoring System that measure O_2 concentration, volumetric gas flow, and O_2 mass emissions to calculate CO_2 emissions

As previously stated, if you are required to use CEMS under 40 CFR Part 75, you should also measure and report your CO_2 emissions to the California Registry using this method. You must also specify which CEMS configuration you are using to monitor your CO_2 emissions. If you do report using CEMS, you must continue to use CEMS for those same facilities each year to ensure consistency over time.

As discussed above, the California Registry requires that participants identify and report biomass CO_2 emissions as "biogenic emissions," separate from fossil fuel emissions. Thus, if you combust biomass fuels in any of your units using CEMS to report CO_2 emissions, you must calculate the emissions associated with the biomass fuels (
Equation 5.a) and subtract this from your total measured emissions (

Equation 5.b). You must report these separate from your fossil emissions, along with any other biogenic emissions.

Equation 5.a. Calculating Biomass Carbon Dioxide (CO_2) Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	**=**	Fuel Consumed (MMBtu)	**x**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	0.001 metric tons/kg

[5] U.S. EPA, Clean Air Markets Division, *Part 75 CEMS Field Audit Manual*, July 16, 2003.

Equation 5.b. Backing Out Biomass Carbon Dioxide (CO_2) Emissions from CEMS

Total Emissions (metric tons)	=	Total CEMS CO_2 Emissions (metric tons)	-	Total Biomass CO_2 Emissions (metric tons)

Example 5.1 illustrates a case where biomass is co-fired and emissions are monitored through a CEMS.

Example 5.1. Biomass Co-Firing in a Unit with CEMS

An electric utility company operating in California reports the CO_2 emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO_2 emissions from this unit, the utility must calculate the portion of CO_2 emissions from combusting wood, and subtract it from the total emission measurement. To do so, the company must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO_2 emission factor. This value is then subtracted from the total CO_2 emissions measured by the CEMS. See
Equation 5.a and

Equation 5.b below.

Equation 5.1.a. Calculating Biomass Carbon Dioxide (CO_2) Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	**=**	Fuel Consumed (MMBtu)	**x**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	0.001 metric tons/kg		
Total Emissions (metric tons)	**=**	1,000,000 MMBtu	**x**	93.87 kg CO_2/MMBtu	**x**	0.001 metric tons/kg	=	93,870 metric tons CO_2

Equation 5.1.b. Backing Out Biomass Carbon Dioxide (CO_2) Emissions from CEMS

Total Emissions (metric tons)	=	Total CEMS CO_2 Emissions (metric tons)	-	Total Biomass CO_2 Emissions (metric tons)		
Total Emissions (metric tons)	=	8,000,000 metric tons CO_2	-	93,870 metric tons CO_2	=	7,906,130 metric tons CO_2

5.2.2 Fuel Use Calculation-Based Methodology

To calculate your GHG emissions based on fuel use, you must determine how much and what type of fuel was combusted, determine how much of the fuel is oxidized in the combustion process, and determine its CO_2 content.

To calculate CO_2, CH_4, and N_2O emissions from stationary combustion, you should:

1. Identify the annual consumption of each fossil and non-fossil fuel type combusted in your operations
2. Apply a heat content factor to convert fuel use from physical units to energy units.
3. Calculate or select the appropriate emission factor for each fuel
4. Calculate each fuel's CO_2 emissions and convert to metric tons
5. Calculate each fuel's CH_4 and N_2O emissions, if any, and convert to metric tons
6. Convert CH_4 and N_2O emissions to CO_2 equivalent and sum all subtotals

Each of these steps is explained in further detail below.

Step 1: Identify the annual consumption of each fossil and non-fossil fuel.

First, determine your annual fuel use by fuel type, measured in terms of physical units (e.g. mass or volume). For stationary combustion sources, you may use one of two methods, listed below, from most accurate to least accurate. Note that while either one is acceptable for reporting to the California Registry, as the methods decrease in accuracy, they also increase in the level of verification required.

Step 1a. Methods for obtaining fuel use data.

Step 1a-1. On-site measurements.

Determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point. Then, sum the fuel use for each unit to arrive at the facility-wide fuel use. If you have a facility-wide fuel totalizer, you can use the amount of fuel from the totalizer.

Step 1a-2. Calculate annual mass balance.

Using fuel purchase records and your fuel inventory log, calculate your total fuel usage. Convert fuel purchase and storage data to estimates of actual fuel use using Equation 5.c:

Equation 5.c. Calculating Actual Annual Fuel Usage

$$\textbf{Total Annual Fuel Burned} = \text{Annual Fuel Purchases} + [\text{Fuel Stock at Beginning of Year} - \text{Fuel Stock at End of Year}]$$

Step 2: Convert fossil fuel use from physical units to energy units.

At this point, your total fuel use is expressed in physical units (mass or volume). Before you can apply a CO_2 emission factor, you must first convert the physical units to heat content (HC), expressed in million British thermal units (MMBtu).

You can use one of three methods to report heating values:

1. Direct measurement according to industry-approved methods
2. Fuel supplier-provided

3. Approved default factors

Default heat content values for each fuel type are provided in Table 5.3, below. You should calculate heat content based on higher heating values (HHV). (See GRP for discussion of converting HHV to LHV).

Step 3: Apply or derive an appropriate CO_2 emission factor for each fuel.

After determining the amount of fuel combusted (expressed in energy content, MMBtu), you must next determine the amount of CO_2 emitted into the atmosphere per unit of fuel. To calculate this information you can use an emission factor obtained from an approved source, listed in Step 3a. To derive your emission factor based on your specific fuel purchases, you follow the guidance in Step 3b.

Step 3a.

To identify your general emission factor, you can use any of the three following methods. These are listed beginning with the most accurate:

1. **Monitoring over a range of conditions and deriving emission factors.** Periodic source testing according to industry-approved methods.
2. **Equipment manufacturer data.** Emission performance guaranteed by manufacturer testing and verification.
3. **Default emission factors.** Fuel-specific CO_2 emission factors representing average fuel and technology characteristics.

Table 5.2. Default CO_2 emission factors by fuel type.

Fossil Fuel	Emission Factor (kg CO_2/MMBtu)
Anthracite Coal	103.62
Bituminous Coal	93.46
Sub-bituminous Coal	97.09
Lignite Coal	96.43
Coke	113.67
Natural Gas	53.06
Distillate Oil	73.15
Residual Oil	78.80
Kerosene	72.31
Petroleum Coke	102.12
LPG	63.16
Ethane	59.58
Propane	63.07
Isobutane	65.08
n-Butane	64.97
Wood – dry (12% moisture content)	93.87
Landfill gas	52.07
Waste water treatment biogas	52.07

Sources: U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: Heat Content factors for Coal (by sector), and Carbon Content and Heat Content factors for Coke and LPG and all factors for Wood and Wood Waste and Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Tables B-1 and B-2).A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change, Guidelines for National Greenhouse Gas Inventories (2006).

For additional emission factors for other fuels used in stationary combustion, see the GRP.

Step 3b.
To derive your emission factor, follow this three-step process:

1. **Determine the carbon content of the fuel**. You can obtain this information either directly from your fuel supplier based on the actual content of the fuel you purchase, or you can use a default factor, provided in Table 5.3 below.
2. **Multiply by an oxidation fraction**. Inefficiencies in the combustion process prevent all the carbon in fossil fuels from oxidizing into CO_2. As a result, a small fraction of the carbon remains unburned as soot or ash, but this is different for each fuel. To identify how much of the carbon in your fuel is oxidized, multiply your purchases of each fuel by its respective oxidation factor, identified in Table 5.3.
3. **Convert to CO_2**. After determining the oxidized carbon content of a fuel, the last step is to convert from carbon emissions to carbon dioxide emissions. Multiply this amount by the molecular weight of CO_2 over carbon (44/12).

This process is outlined in Equation 5.d below.

Equation 5.d. Emission Factor Derivation

$$\textbf{Emissions} = \sum_{i=1}^{n} \text{Fuel} \times \text{HC} \times \left[\text{CC} \times \text{OF} \times \frac{CO_{2\,(m.w.)}}{C_{(m.w.)}} \right]$$

Where,

		Units
Fuel	Mass or Volume of the Fuel Type *i* Combusted	
HC_i	Heat Content of Fuel Type *i*	(energy / mass or volume of fuel)
CC_i	Carbon Content Coefficient of Fuel Type *i*	(mass C / energy)
OF_i	Oxidation Fraction of Fuel Type *i*	
$CO_{2\,(m.w.)}$	Molecular weight of CO_2	
$C_{(m.w.)}$	Molecular weight of C	

Table 5.3. Default values for heat content, carbon content, and fraction of carbon oxidized for fuels used for electric power generation.

Fossil Fuel	Heat Content (HHV)	Carbon Content	Fraction Oxidized
Coal and Coke	**(MMBtu/short ton)**	**(kg C/MMBtu)**	
Anthracite Coal	25.09	28.26	1.00
Bituminous Coal	24.93	25.49	1.00
Sub-bituminous Coal	17.25	26.48	1.00
Lignite Coal	14.21	26.30	1.00
Coke	24.80	31.00	1.00
Natural Gas	**(Btu/standard ft^3)**	**(kg C/MMBtu)**	
Natural Gas	1,029.00	14.47	1.00
Petroleum	**(MMBtu/barrel)**	**(kg C/MMBtu)**	
Distillate Oil	5.825	19.95	1.00
Residual Oil	6.287	21.49	1.00
Kerosene	5.670	19.72	1.00
Petroleum Coke	6.024	27.85	1.00
LPG	3.849	17.23	1.00
Ethane	2.916	16.25	1.00
Propane	3.824	17.20	1.00
Isobutane	4.162	17.75	1.00
n-Butane	4.328	17.72	1.00
Non-Fossil Fuel	**Heat Content (HHV)**	**Carbon Content**	**Fraction Oxidized**
Solid	**(MMBtu/short ton)**	**(kg C/MMBtu)**	
Wood – dry (12% moisture content)	15.38	25.60	1.00
Gas	**(Btu/standard ft^3)**	**(kg C/MMBtu)**	
Landfill gas	502.50	14.20	1.00
Waste water treatment biogas	Varies (obtain from operator)	14.20	1.00

Sources: U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: Heat Content factors for Coal (by sector), and Carbon Content and Heat Content factors for Coke and LPG and all factors for Wood and Wood Waste and Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Tables B-1 and B-2).A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change, Guidelines for National Greenhouse Gas Inventories (2006).

Step 4: Apply CH_4 and N_2O emission factors for each fuel.

During the hydrocarbon combustion process, N_2O formation follows complex pathways and depends on a variety of factors, including fuel type and combustion technology and configuration. CH_4 formation is usually dependent on conditions similar to those that create N_2O. Therefore, the following emission factors for CH_4 and N_2O are broken down by fuel type, combustion technology, and equipment configuration. This contrasts with CO_2 emission factors, which are almost exclusively dependent on fuel type.

Table 5.4. Default CH_4 and N_2O emission factors for fossil fuels.

Fossil Fuel	Combustion Technology	Equipment Configuration	CH_4 (kg/MMBtu)**	N_2O (kg/MMBtu)**
Coal, Bituminous	Pulverized	Dry Bottom, wall fired	0.000728	0.000546
		Dry Bottom, tangentially fired	0.000728	0.001456
		Wet Bottom	0.000910	0.001456
	Spreader Stokers	With and Without Reinjection	0.001092	0.000728
	Fluidized Bed	Circulating Bed	0.001092	0.063681
		Bubbling Bed	0.001092	0.063681
	Cyclone Furnace	NA	0.000182	0.001638
Coal, Sub-bituminous	Pulverized	Dry Bottom, wall fired	0.001052	0.000789
		Dry Bottom, tangentially fired	0.001052	0.002104
		Wet Bottom	0.001315	0.002104
	Spreader Stokers	With and Without Reinjection	0.001578	0.001052
	Fluidized Bed	Circulating Bed	0.001578	0.092033
		Bubbling Bed	0.001578	0.092033
	Cyclone Furnace	NA	0.000263	0.002367
Coal, Lignite	Atmospheric Fluidized Bed		NA	0.079802
Oil	Residual Fuel Oil No.5	Utility Boilers	0.000849	NA
	Residual Fuel Oil No.6		0.000849	0.001606
	Residual Fuel Oil No.5	Industrial Boilers	0.003030	NA
	Residual Fuel Oil No.6		0.003030	0.001606
	Distillate Fuel Oil		0.000170	0.000850
	Large Diesel Fuel Engines >447 kW [a]		0.003674	NA
Natural Gas	Boilers		0.001014	0.000970
	Boilers (Low-NOx Burners)			0.000282
	Gas Fired Turbines >3 MW [b]		0.003901	0.001361
	Large Dual Fired Engines [c]		0.272156	NA

Source: U.S. EPA AP 42, Volume I, Fifth Edition, Chapter 1: External Combustion Sources and Chapter 3: Stationary Internal Combustion Sources; Tables 1.1-19, 1.3-3, 1.3-8, 1.4-2, 1.7-4, 3.1.2a, and 3.4-1 (January 1995, updates completed in 2000).

** U.S. EPA Table 1.1-19 provides emission factors as lb/short ton. To convert lb/short ton to kg/MMBtu the California Registry uses heat content values (MMBtu/short ton) for bituminous, sub-bituminous, and lignite from GRP Version 3.1 Table C.7. For all fuel types converted from pounds to kilograms, the conversion factor of 0.453592 was used.
[a] Source values given as Total Organic Content containing 9% methane by weight.
[b] Emission factors to be applied on units operating at high loads (≥80 percent load).
[c] Assumes fuel composition is 95% natural gas and 5% diesel fuel.
Note: all emission factors correspond to uncontrolled emissions.

Step 5: Calculate each fuel's CO_2 emissions and convert to metric tons.

If your fuel consumption is expressed in MMBtu, use

Equation 5.e. If your fuel is expressed in mass units (i.e. gallons, short tons, cubic feet, etc.), use Equation 5.f.

Equation 5.e. Total CO_2 Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation 5.f. Total CO_2 Emissions (Fuel Consumption is in Mass Units)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CO_2/mass unit)	x	Fuel Consumed (mass unit)	x	0.001 metric tons/kg

Step 6: Calculate each fuel's CH_4 and N_2O emissions, if any, and convert to metric tons.

If your fuel consumption is expressed in MMBtu, calculate CH_4 emissions using Equation 5.g and N_2O emissions using Equation 5.h. If fuel consumption is expressed in mass units, use Equation 5.i and Equation 5.j.

Note that if non-CO_2 gases are de minimis after they are converted to CO_2e and metric tons, you must still disclose them as de minimis in CARROT and the PUP Report. Also, you are encouraged, but not *required* to report non-CO_2 emissions until your fourth calendar year of reporting to the California Registry.

Equation 5.g. Total CH_4 Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation 5.h. Total N_2O Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation 5.i. Total CH_4 Emissions (Fuel Consumption is in Mass Units)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/Mass Units)	x	Fuel Consumed (Mass Units)	x	0.001 metric tons/kg

Equation 5.j. Total N_2O Emissions (Fuel Consumption is in Mass Units)

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg N_2O/Mass Units)	x	Fuel Consumed (Mass Units)	x	0.001 metric tons/kg

Step 7: Convert CH_4 and N_2O emissions to CO_2 equivalent and sum all subtotals.

To incorporate and evaluate non-CO_2 gases in your GHG emissions inventory, you must convert the mass estimates of these gases to CO_2 equivalent. To do this, multiply the emissions in units of mass by their global warming potentials (GWP). Table 5.5 below lists the 100-year GWPs to be used to express emissions on a CO_2 equivalent basis.

Note that in CARROT and the PUP Report, emissions should be reported as the specific GHG. CARROT and the PUP Report will then convert this data into CO_2 equivalent.

Equation 5.k. Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e	**=**	Metric Tons of GHG	x	GWP

Table 5.5. Comparison of GWPs from the IPCC's Second and Third Assessment Reports.

Greenhouse Gas	GWP [SAR, 1996]	GWP [TAR, 2001]
CO_2	**1**	1
CH_4	**21**	23
N_2O	**310**	296
HFC-23	**11,700**	12,000
HFC-32	**650**	550
HFC-125	**2,800**	3,400
HFC-134a	**1,300**	1,300
HFC-143a	**3,800**	4,300
HFC-152a	**140**	120
HFC-227ea	**2,900**	3,500
HFC-236fa	**6,300**	9,400
HFC-4310mee	**1,300**	1,500
CF_4	**6,500**	5,700
C_2F_6	**9,200**	11,900
C_3F_8	**7,000**	8,600
C_4F_{10}	**7,000**	8,600
C_6F_{14}	**7,400**	9,000
SF_6	**23,900**	22,000

Source: Intergovernmental Panel on Climate Change, Second Assessment Report (1996) and Third Assessment Report (2001).

5.2.3 Biogenic Emissions

As stated above, the California Registry distinguishes between fossil fuel emissions (anthropogenic emissions) and non-fossil fuel emissions (biogenic emissions). In reporting your GHG emissions inventory, you should include all of your anthropogenic emissions in your CARROT and PUP reports. Consistent with international practice at this time, you are also required to document your biogenic emissions used for stationary combustion, but you should report them separately from your direct emissions from stationary combustion. Biogenic CO_2 emissions from power/utility companies must be disclosed in the PUP Report. The same step-by-step procedure to determine GHG emissions from fossil fuels applies to non-fossil fuels.

For municipal solid waste-to-energy facilities (MSW), you must calculate your CO_2 emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include it in your GHG emissions inventory. However, your CO_2 emissions from combusting the biomass portion of MSW (e.g. yard waste, paper products, etc.) should be recorded as "biogenic emissions". Information on the biomass portion of MSW will be site-specific and should be obtained from a local waste characterization study.

5.2.4 Calculating Stationary Combustion for California Reporting

If you are reporting only your California emissions and you generate and deliver electricity to customers in California, you will calculate your stationary combustion emissions according to the guidance in this section for all electricity generation from stations located in California.

For California reporting, you should report all of the emissions associated with plants physically located in the state.

Note that to calculate your required efficiency metrics, for each plant that you own outside of California but that provides power to your customers in California, you will need to know the emissions from fuel combustion associated with the portion of electricity you generate that is delivered to California. This is true regardless of the physical location of the plant.

If you share ownership of the plant, you should only report the portion of emissions for which you are responsible, and the portion of emissions delivered to California. If you are reporting by equity share, this will correspond to your ownership share (Note: equity share is the preferred method of reporting for the power/utility sectors). For instance, if you have 50% ownership of a plant that delivers 80% of its output to California customers, you would report half of the emissions associated with 80% of the plant's output. If you are reporting using management control, you will report either 100% or none of the emissions associated with the output delivered to California.

Because the resources of the electricity deliveries are known, you should use the GHG emission factor associated with that purchase.

Example 5.2. Calculating Direct Emissions from Stationary Combustion

AB Power Corporation

AB Power is an electric utility operating in California. It has two 800 MW generating units, one in California that burns natural gas and one at a mine mouth in Wyoming that combusts bituminous coal in dry bottom, wall-fired boilers. All of the generation from its California unit serves its California customers; 80% of the power generated at its Wyoming unit serves California customers. AB Power also owns a natural gas pipeline system in California, which includes natural gas compressor stations that combust natural gas.

Step 1: Identify all types of fuel directly combusted.

Table 5.6. Fuel Type, Sector, and Location

Fuel	Sector	Location
Natural Gas	Electric Power Generation	California
Natural Gas	Natural Gas System	California
Coal	Electric Power Generation	Wyoming

Step 2: Determine annual consumption of each fuel.
AB Power directly measures the energy content (MMBtu) of the fuel used in both of its power plants and its natural gas compressor stations. From fuel purchase records, AB Power determined that last year it consumed 10,000,000 MMBtu of natural gas and 22,000,000 MMBtu of coal for power generation. It also consumed 1,000,000 MMBtu of natural gas in its compressor stations.

Step 3: Select the appropriate emission factor for each fuel from Tables 5.2 and 5.3.

Step 4: Calculate each fuel's CO_2 emissions.

Equation . Carbon Dioxide (CO_2) Emissions from Natural Gas

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	Fuel Consumed (MMBtu)	**x**	0.001 metric tons/kg		
Total Emissions (metric tons)	**=**	53.06 kg CO_2/MMBtu	**x**	10,000,000 MMBtu	**x**	0.001 metric tons/kg	**=**	530,600 metric tons CO_2

Equation 5.j. Carbon Dioxide (CO_2) Emissions from Coal

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	Fuel Consumed (MMBtu)	**x**	0.001 metric tons/kg		
Total Emissions (metric tons)	**=**	93.46 kg CO_2/MMBtu	**x**	22,000,000 MMBtu	**x**	0.001 metric tons/kg	**=**	2,056,120 metric tons CO_2

Equation 5.k. Carbon Dioxide (CO_2) Emissions from Natural Gas (compressor stations)

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg CO_2/MMBtu)	**x**	Fuel Consumed (MMBtu)	**x**	0.001 metric tons/kg		
Total Emissions (metric tons)	**=**	53.0 kg CO_2/MMBtu	**x**	1,000,000 MMBtu	**x**	0.001 metric tons/kg	**=**	53,060 metric tons CO_2
						Total CO_2 from All Sources	**=**	**2,639,780 metric tons CO_2**

Step 5: Calculate each fuel's CH_4 and N_2O emissions.

Equation 5.l. Methane (CH_4) Emissions from Natural Gas

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.001014kg CH_4/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg	=	10.14 metric tons CH_4

Equation 5.m. Methane (CH_4) Emissions from Coal

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	X	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000728 kg CH_4/MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg	=	16.02 metric tons CH_4

Equation 5.n. Methane (CH_4) Emissions from Natural Gas (compressor stations)

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg CH_4/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.001014kg CH_4/MMBtu	x	1,000,000 MMBtu	x	0.001 metric tons/kg	=	1.01 metric tons CH_4
						Total CH_4 from All Sources	=	**27.17 metric tons CH_4**

Equation 5.o. Nitrous Oxide (N_2O) Emissions from Natural Gas

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000970 kg N_2O/MMBtu	x	10,000,000 MMBtu	x	0.001 metric tons/kg	=	9.7 metric tons N_2O

Equation 5.p. Nitrous Oxide (N_2O) Emissions from Coal

Total Emissions (metric tons)	=	Adjusted Emission Factor (kg N_2O/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg		
Total Emissions (metric tons)	=	0.000546 kg N_2O/MMBtu	x	22,000,000 MMBtu	x	0.001 metric tons/kg	=	12.01 metric tons N_2O

Equation 5.q. Nitrous Oxide (N_2O) Emissions from Natural Gas (compressor stations)

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg N_2O/MMBtu)	**x**	Fuel Consumed (MMBtu)	**x**	0.001 metric tons/kg		
Total Emissions (metric tons)	**=**	0.000970 kg N_2O/MMBtu	**x**	1,000,000 MMBtu	**x**	0.001 metric tons/kg	**=**	0.97 metric tons N_2O
						Total N_2O from All Sources	**=**	**22.68 metric tons N_2O**

In this case, it is likely that both methane and nitrous oxide emissions from stationary combustion are de minimis. See Section 10: Calculating De Minimis Emissions for more information on de minimis emissions.

Step 6: Convert CH_4 and N_2O Emissions to CO_2e and sum the subtotals.

Equation 5.r. Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e = Metric Tons of GHG x GWP

Metric Tons of CO_2					**=**	2,639,780 metric tons CO_2
CH_4 Metric Tons of CO_2e	**=**	metric tons CH_4	x	21	**=**	570.57 metric tons CO_2e
N_2O Metric Tons of CO_2e	**=**	metric tons N_2O	x	310	**=**	7,030.80 metric tons CO_2e
				Total	**=**	**2,647,381.37 metric tons CO_2e**

Step 7: If California-only reporting, report only the emissions associated with facilities in California.

Equation 5.r. Calculating Out of State Generation Delivered to California (CH_4 and N_2O Emissions from Natural Gas)

Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP		
Metric Tons of CO_2					**=**	530,600 metric tons CO_2
CH_4 Metric Tons of CO_2e	**=**	10.14 metric tons CH_4	x	21	**=**	212.94 metric tons CO_2e
N_2O Metric Tons of CO_2e	**=**	9.7 metric tons N_2O	x	310	**=**	3,007 metric tons CO_2e
				Total	**=**	**533,819.94 metric tons CO_2e**

6 Direct Emissions from Processes

This section provides guidance on quantifying direct emissions from power generation processes, including controlling emissions from power generation facilities. You may need information on your SO_2 and NO_x emission control technology systems installed on your electric generating units, specifications of certain electric generation facilities as appropriate, and the quantity of calcium carbonate utilized.

This protocol does not currently include guidance for calculating and reporting the CH_4 and CO_2 emissions from natural gas transmission, storage and distribution systems which may represent a significant portion of a utility's process emissions. You will need to follow industry best practice guidance for calculating your process emissions from natural gas systems.

In addition to stationary combustion emissions, you must account for any process-related GHG emissions that you have. These include:

- SO_2 scrubber emission control technology installed on many coal- and oil-fired electric generating units
- NO_x emission control technologies such as selective catalytic reduction (SCR) and selective non catalytic reduction (SNCR) technologies
- Coal gasification at coal facilities, e.g. integrated gasification combined cycle (IGCC)
- Hydrogen production

Note that the workgroup was unable to identify standardized methods to quantify process-related GHG emissions for hydrogen production, SCR, SNCR, and IGCC technologies.

6.1 SO_2 Scrubbers

Any wet flue gas desulfurization systems, fluidized bed boilers, or other emission controls with sorbent injection likely emit CO_2 during the SO_2 scrubbing process, from the use of calcium carbonate.

If you use CEMS to collect and report emissions data to the California Registry for stationary combustion units that have SO_2 scrubbers installed, then the CEMS also capture the CO_2 emissions from the scrubbing.

If you are not reporting using CEMS and you have SO_2 scrubbers on your combustion units, you must follow the guidance in this section to quantify your process CO_2 emissions associated with SO_2 scrubbing.[6]

To calculate these process emissions follow the steps outlined below:

Step 1: Determine the total quantity of sorbent used.

Using your company's purchase records, determine the total quantity of sorbent (tons of calcium carbonate ($CaCO_3$) used each year). Identify your total sorbent inventory at the beginning of year, your total sorbent purchases during the year, and your total sorbent inventory at year end.

Use the values in Equation 6.a.

[6] This methodology can be found in the U.S. EPA's CEMS guidelines and procedures. For more information on EPA's CEMS guidelines and procedures, reference (40 CFR Part 75).

Equation 6.a. Annual Quantity of Sorbent Used

Total Sorbent Used	**=**	[Total inventory at beginning of year	-	Total inventory at end of year]	+	Total purchases/ acquisitions

Step 2: Calculate the ratio of the molecular weight of CO_2 to the sorbent.

Divide the molecular weight of carbon dioxide (44) by the molecular weight of the calcium carbonate (100) and multiply by the calcium to sulfur stoichiometric ratio (1.00).

Equation 6.b. Ratio of the Molecular Weight of $CO_2/CaCO_3$

Ratio of the Molecular Weight $CO_2/CaCO_3$	**=**	Molecular Weight of CO_2 (44)	/	Molecular Weight of $CaCO_3$ (100)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)

Step 3: Determine CO_2 emissions and convert to metric tons.

Multiply the value obtained in Step 2 above by the total short tons of $CaCO_3$ used to determine CO_2 emissions. Multiply by 0.907 to convert to metric tons. See Equation 6.c below.

Equation 6.c. Total Process Emissions (Metric Tons)

Total Process CO_2 Emissions (metric tons)	**=**	[Calcium Carbonate Used (short tons)	x	Ratio of the Molecular] Weight of CO_2/ $CaCO_3$	x	0.907 metric tons/short ton

Example 6.1. Calculating Process Emissions from SO_2 Scrubber Sorbent

AB Power Corporation

AB Power owns an 800 MW coal-fired electric generating facility in Wyoming. To comply with the federal Acid Rain Program, it installed SO_2 scrubbers that use calcium carbonate as the sorbent for the scrubbers.

AB Power reports all of its CO_2 emissions to the California Registry from this facility. To calculate its stationary combustion, it uses the fuel-based calculation method. Thus, it must also complete the following calculations to calculate the CO_2 emissions associated with operating its scrubbers, and report these as process emissions.

Step 1: Determine the total quantity of sorbent used.

Based on company purchase records, AB Power determined that it used 10,000 tons of calcium carbonate at its Wyoming coal facility in its scrubber technology.

Table 6.1. Calcium Carbonate Use and Location

Location	Quantity of Calcium Carbonate Used (Short Tons or Tons)
Wyoming	10,000

Step 2: Multiply the total quantity of sorbent by the ratio of the molecular weight of CO_2 to the sorbent.

Equation 6.a. Annual Quantity of Sorbent Used

Total Sorbent Used	**=**	[Total inventory at beginning of year	**-**	Total inventory] at end of year	+	Total purchases/ acquisitions
10,000 tons	**=**	[9000 (tons)	**-**	9000 (tons)]	+	10,000 (tons)

Equation 6.b. Ratio of the Molecular Weight of $CO_2/CaCO_3$

Ratio of the Molecular Weight $CO_2/CaCO_3$	=	Molecular Weight of CO_2 (44)	/	Molecular Weight of $CaCO_3$ (100)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)		
Ratio of the Molecular Weight $CO_2/CaCO_3$	=	44	/	100	x	1.00	=	0.44

Step 3: Determine CO_2 emissions and convert to metric tons.

Equation 6.c. Total Process Emissions (Metric Tons)

Total Process CO_2 Emissions (metric tons)	**=**	Calcium Carbonate Used (Tons)	x	Calcium to Sulfur Stoichiometric Ratio (1.00)	x	Molecular Weight of CO_2 (44)/Molecular Weight of $CaCO_3$ (100)	x	0.907 metric tons/short ton		
Total Process CO_2 Emissions (metric tons)	**=**	10,000 tons	x	1.00	x	0.44	x	0.907	=	3,991 metric tons CO_2

7 Direct Fugitive Emissions

This section provides guidance on quantifying fugitive emissions from electric power transmission and distribution, and solid fuel storage and handling. You may need information on your total annual purchases of SF_6 and solid fuel.

This protocol does not currently include guidance for calculating and reporting the CH_4 and CO_2 emissions from natural gas transmission, storage and distribution systems which may represent a significant portion of a utility's fugitive emissions. Refer to industry best practice guidance for reporting emissions from natural gas transmission, storage & distribution.

Fugitive emissions are unintentional releases of GHGs, for instance from joints, seals, and gaskets. Fugitive emissions from the power/utility sector include:

1. Sulfur hexafluoride (SF_6) from electricity transmission and distribution systems
2. CH_4 from fuel handling and storage
3. Hydrofluorocarbons (HFCs) from air conditioning and refrigeration systems (both stationary and mobile)
4. Perfluorocarbons (PFCs) and HFCs from fire suppression equipment

These sources are listed by segment, facility and equipment in Table 7.1 below.

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting direct fugitive emissions from:

- Air conditioning and refrigeration systems (both stationary and mobile)
- Fire suppression equipment

Note that for most power/utility companies, CH_4 emissions from fuel handling and storage and emissions of PFCs/HFCs may be de minimis. For information on estimating the impact of these emissions, see Section 10: Calculating De Minimis Emissions.

Table 7.1. Fugitive emission sources within power/utility sectors.

<table>
<tr><th colspan="4">Fugitive SF_6 Sources</th></tr>
<tr><th>Segment</th><th colspan="3">Equipment</th></tr>
<tr><td>Electricity Transmission</td><td colspan="3">Circuit Breakers, Current-Interruption Equipment, Transmission Lines, Transformers, Substations</td></tr>
<tr><td>Electricity Distribution</td><td colspan="3">Circuit Breakers, Current-Interruption Equipment, Distribution Lines, Transformers, Substations</td></tr>
<tr><th colspan="4">Other Fugitive Emission Sources</th></tr>
<tr><th>Segment</th><th>Facilities</th><th>Source</th><th>Emissions</th></tr>
<tr><td>Solid Fuel Handling and Storage</td><td>Electric Generation Facilities, Fuel Storage Facilities</td><td>Coal Piles, Biomass Piles</td><td>CH_4</td></tr>
<tr><td>Stationary and Mobile Cooling and Refrigeration</td><td>Electric Generation Facilities, Office Buildings, Mobile Sources</td><td>Air Conditioning and Refrigeration Systems</td><td>HFCs</td></tr>
<tr><td>Fire Extinguishers</td><td>Electric Generation Facilities</td><td>Total Flooding Fire Extinguishing Systems</td><td>PFCs and HFCs</td></tr>
</table>

7.1 Fugitive Emissions from Electricity Transmission and Distribution

Within the electric power industry, SF_6 is a gas often used for electrical insulation, arc quenching, and current interruption equipment used to transmit and distribute electricity. SF_6 is extremely stable and long lasting, and is also a potent greenhouse gas. It is estimated that the electric power industry uses about 80% of the SF_6 produced worldwide, with circuit breaker applications accounting for most of this amount.[7]

Fugitive SF_6 emissions from the electric utility industry are the result of normal operations and routine maintenance, as well as the use of older equipment. SF_6 can escape to the atmosphere during normal operations, releases from properly functioning equipment (due to both static and dynamic operation) and old and/or deteriorated gaskets or seals. SF_6 can also escape when gas is either transferred into or extracted from equipment for disposal, recycling, or storage.

7.2 Fugitive Emissions from Solid Fuel Handling and Storage

Fugitive emissions from solid fuel handling and storage are the result of:

- CH_4 desorption from coal handling and storage
- CH_4 and N_2O from decomposing
- Other causes

Fugitive emissions from fuel handling and storage will likely be de minimis for power/utility entities. For help in determining whether your fugitive CH_4 emissions from fuel handling and storage are de minimis, see Section 10: Calculating De Minimis Emissions.

7.2.1 Coal Handling & Storage

In the course of mining, transporting, and storing coal used for power generation, methane is emitted from underground mining, surface mining, and post-mining activities. Some methane remains in the coal after it is removed from the mine and can be emitted as the coal is transported, processed, and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for weeks or months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses.[8] The actual amount of gas that escapes into the atmosphere will be a function of the rate of methane desorption, the coal's original gas content, and the amount of time elapsed before coal combustion occurs.

7.2.2 Biomass Handling & Storage

In the handling and storage of biomass, methane is formed where anaerobic digestion occurs. Whether or not anaerobic conditions occur in the pile largely depends on the characteristics of the pile and its surroundings (height, surface, temperature) and the content of the biomass itself (particle size, density, moisture content). Biomass piles may also be a source of nitrous oxide emissions during the first stage of decomposition. [9]

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[7] Other uses of SF_6 include: semiconductor processing, blanket gas for magnesium casting, reactive gas in aluminum recycling to reduce porosity, thermal and sound insulation, airplane tires, spare tires, "air sole" shoes, scuba diving voice communication, leak checking, atmospheric tracer gas studies, ball inflation, torpedo propeller quieting, wind supersonic channels, and high voltage insulation for many other purposes, such as AWACS radar domes and X-ray machines.

[8] U.S. EPA, 1990.

[9] Consistent with international practice, CO_2 emissions from the combustion of biomass fuels used in electricity generation must be quantified and reported as biogenic emissions, but are not included in your total GHG emissions inventory, which tracks anthropogenic emissions. For more information on calculating these emissions, see *Section 5: Direct Emissions from Stationary Combustion*.

7.3 Quantifying Fugitive SF_6 Emissions from Electricity Transmission and Distribution

To calculate your fugitive SF_6 emissions from electricity transmission and distribution operations, you should use the Mass Balance Approach, as outlined in the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. The complete methodology is provided in Appendix A to this protocol. An overview of the process is provided below.

7.3.1 Mass Balance Approach

This method uses a mass balance approach to calculate total fugitive SF_6 emissions.

Calculate your fugitive SF_6 emissions using the following seven-step process:

1. Determine change in SF_6 inventory
2. Determine purchases/acquisitions of SF_6
3. Determine sales/disbursements of SF_6
4. Determine the net increase in the total nameplate capacity of the equipment
5. Determine total annual emissions (1+2-3-4)
6. Convert SF_6 emissions to CO_2 equivalent
7. Determine emission rate (optional)

8 Indirect Emissions from Energy Purchased and Consumed

This section provides guidance on quantifying indirect emissions from electricity purchased and consumed by companies in the power/utility sector. Indirect emissions are those that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity. You may need information on your total annual purchases and deliveries of electricity.

8.1 T&D Line Loss Sources in the Power/Utility Sectors

If you own transmission and/or distribution assets, you are responsible to report the electricity losses that occur in those systems. Since these losses are classified as “consumption” of the electricity, they are categorized as indirect emissions. Sources of transmission and distribution line losses include those areas and sources listed in Table 8.1 below.

Table 8.1. Transmission and Distribution Line Loss Sources

Segment	Facilities	Equipment
Electricity Transmission	Feeders and Transmission Lines	Transformers/Wires, Conductors
Electricity Distribution	Distribution Systems and Substations	Transformers/Wires

You must report the following indirect emissions:

1. **Indirect emissions associated with transmission and/or distribution losses.** These are the emissions associated with 1) the portion of the electricity purchased for resale to

end-users that is consumed by your T&D system, and 2) the portion of wheeled electricity that is consumed by your T&D system.[10]

2. **Purchased electricity, steam or heat for own consumption.** These are the emissions associated with the generation of purchased electricity, steam, and heating and cooling that is consumed in equipment or operations owned or controlled by your organization (e.g. office buildings).

Reporters should consult the General Reporting Protocol for guidance on calculating and reporting indirect emissions from:

- Electricity, steam or heat purchased for your own consumption

If you are reporting only California emissions, you should follow the steps in this section to calculate the emissions associated with T&D losses serving customers in California only and energy purchased and consumed at facilities in California only.

8.2 Quantifying Indirect Emissions Associated with Transmission & Distribution Losses

This section provides a default method for quantifying indirect GHG emissions associated with your consumption of purchased and wheeled electricity on your T&D system (T&D losses).

If you own and/or operate a transmission and/or distribution system, you must report the portion of indirect emissions associated with the amount of purchased and wheeled electricity that corresponds to your entity-wide T&D losses.

Note that you do not need to account for the T&D losses associated with electricity that you generate and sell to end-users. These emissions are already reported in your inventory as direct stationary combustion emissions.

However, if you purchase electricity and resell it to end-users, you must report the indirect emissions associated with transmission and/or distribution of this electricity. You should also separately report the indirect emissions associated with transmission and distribution of wheeled electricity (including direct access).

8.2.1 Sources of Information on T&D Losses

Your organization may already track the data necessary to report using this methodology for state, federal or independent system operator (ISO) reporting purposes. For example, your organization may be required to report to the Federal Energy Regulatory Commission (FERC) under *FERC FORM 1 - Annual Report of Major Electric Utility*, to the U.S. Energy Information Administration (EIA) under *The Annual Electric Power Industry Report, Form EIA-861* or Public Electric Utility Database Form EIA-412**.**

If you currently report FERC FORM 1, all information required to use this methodology is contained on:

- Page 401: *Electrical Energy Account*
- Page 327: *Purchased Power*
- Page 328: *Transmission of Electricity for Others*

[10] Wheeled electricity includes direct access (customer choice programs) where the T&D utility only transmits and/or distributes the power.

8.2.2 Calculate T&D Losses

Calculate your transmission and/or distribution losses using the following fourteen steps:

1. Identify the total net generation
2. Identify the total purchases from electricity suppliers
3. Identify exchanges (net)
4. Identify wheeled (net)
5. Identify transmission by others (losses)
6. Identify total sources
7. Identify retail sales to ultimate customers
8. Identify sales for resale
9. Identify energy furnished without charge
10. Identify energy consumed by respondent without charge
11. Identify energy consumed by facility (Independent Power Producers or Qualifying Facility)
12. Identify total energy losses
13. Identify T&D loss factor
14. Identify portion of losses attributable to purchases and wheeled power

Each of these fourteen steps to calculate your transmission and/or distribution losses is described in greater detail below.

Step 1: Identify your total net generation.

Determine your net generation (gross generation minus plant use) in megawatt hours (MWh).

Step 2: Identify the total purchases from electricity suppliers.

Add your total purchases (MWh) from all electricity suppliers including: nonutility power producers and power marketers, municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, state agencies and power pools, and marketing agencies.

Step 3: Identify exchanges (net).

Determine the net amount of energy exchanged in MWh. Calculate the difference between the amount of exchange received from the amount of exchange delivered.

Step 4: Identify wheeled (net).

Total the difference between the amount of energy entering your owned and/or operated system for transmission through your system and the amount of energy leaving your system in MWh. Determine the energy losses on your system associated with the wheeling of energy for other systems.

Step 5: Identify transmission by others (losses).

Calculate the amount of energy losses in MWh associated with the wheeling of electricity provided to your owned and/or operated system by other utilities. Transmission by others (losses) should always be expressed as a negative value.

Step 6: Identify total sources.

Calculate the sum of the energy sources (net generation, purchases from electricity suppliers, exchanges (net), wheeled (net), and transmission by others (losses)).

Step 7: Identify retail sales to ultimate customers.

Identify the amount of electricity in MWh sold to customers purchasing electricity for their own use and not for resale

Step 8: Identify sales for resale.

Determine the amount of electricity in MWh sold for resale purposes. This entry should include sales for resale to power marketers, full and partial requirements (firm) customers and to non-requirements (nonfirm) customers.

Step 9: Identify energy furnished without charge.

Identify the amount of electricity in MWh furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting.

Step 10: Identify energy consumed without charge.

Determine the amount of electricity in MWh used by the electric utility in its electric and other departments without charge.

Step 11: Identify energy consumed by facility (Independent Power Producers or Qualifying Facility).

Calculate the amount of electric energy in MWh consumed at the facility in support of a service or manufacturing process.

Step 12: Identify total energy losses.

Identify the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between total sources and the sum of Retail Sales to Ultimate Customers + Sales for Resale + Energy Furnished Without Charge + Energy Consumed by Respondent Without Charge + Energy Consumed by Facility (Independent Power Producers or Qualifying Facility). Total energy losses should always be expressed as a positive value.

Step 13: Identify T&D loss factor.

Divide total energy losses by total sources to identify the T&D loss factor in percentage terms.

Step 14: Identify portion of losses attributable to purchases and wheeled electricity.

Multiply the T&D loss factor by the total purchases from electricity suppliers and wheeled received (in) to calculate total T&D losses attributable to purchases and wheeled and record these values separately.

8.2.3 Indirect Emissions Associated with T&D Losses

Calculate indirect emissions associated with these T&D losses using the following six steps:

1. Identify the weighted average GHG emission factor of power purchases
2. Identify the weighted average GHG emission factor of wheeled electricity
3. Calculate indirect CO_2 emissions and convert to metric tons
4. Calculate indirect CH_4 emissions and convert to metric tons
5. Calculate indirect N_2O emissions and convert to metric tons
6. Convert GHG emissions to CO_2 equivalent and sum all subtotals

To calculate your weighted average emission factor, you must first determine the emission factor of each power purchase.

Step 1: Identify the weighted average GHG emission factors for power purchases.

To determine a weighted average emissions factor for all electricity purchases, you must first determine the percentage of purchased power derived from each source (spot market, each facility, and each utility) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$\mathbf{E} = (S*S_f) + (F*F_f) + (U*U_f)$$

Where,

E	weighted average emissions factor for purchased power
S	proportion of power purchased from the spot market
S_f	average emission factor for spot purchases (power pool emission factor)
F	proportion of power purchased from a specific facility (for each facility)
F_f	facility-specific emission factor (for each facility)
U	proportion of power purchased from a specific utility (for each utility)
U_f	utility-specific emission factor (for each utility)
	S+F+U = 1

For any electricity purchase whose resources are known (i.e. purchased from a utility or a generator) you should use the GHG emission rate associated with that purchase. This can be the default emission factor from eGRID, or obtained directly from the generator.

If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emissions factors associated with those purchases.

For any power purchased from the spot market, you should use the default emission factor.

Step 2: Identify the weighted average GHG emission factors for wheeled electricity.

For wheeled electricity, if the particular generation resources are known, you should obtain the GHG emission factor of the power from the generator or utility, if available. If your company already tracks this information for compliance with state environmental disclosure rules, you may use this information to quantify the emission factors associated with that wheeled electricity. If generator- or utility-specific emission factors are not available, use the default emission factors found in Table 8.2 (eGRID subregion emission factors).

For all spot market power purchases, use the eGRID subregion emission factors. For guidance regarding eGRID and emission factor resources, see the section below on emission factors.

To determine a weighted average emissions factor for all wheeled electricity, you must first determine the percentage of wheeled power derived from each source (known and unknown resources) and then multiply that percentage by each source-specific emission factor as illustrated in the equation below.

$$\mathbf{W} = (K*K_f) + (U*U_f)$$

Where,

W	weighted average emissions factor for wheeled power
K	proportion of power wheeled from known resources
K_f	average emission factor for known resources
U	proportion of power wheeled from a unknown resources
U_f	regional-specific emission factor (power pool emission factor)

$K+U = 1$

Step 3: Calculate indirect CO_2 emissions and convert to metric tons.

Once you have determined the weighted average CO_2 emission rates for purchased and wheeled power, multiply the MWh losses calculated in Step 2 by the applicable CO_2 emission rates. Sum all CO_2 emissions and convert to metric tons by dividing by 2,204.6.

Equation 8.a. Determining Indirect CO_2 Emissions Associated with Purchased Power

Total Indirect CO_2 Emissions from Purchased Power (metric tons)	**=**	Total Losses Attributed to Purchases (MWh)	x	Weighted Average Emission Factor of Purchased Power (lbs CO_2/MWh)	/	2204.6 lbs/metric ton

While direct access is a portion of your wheeled power, to report to the California Registry, you should distinguish the emissions from direct access from the rest of your wheeled power to provide greater transparency. Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8.b. Determining Indirect CO_2 Emissions Associated with Wheeled Power

$$\textbf{Total Indirect } \mathbf{CO_2} \textbf{ Emissions from Wheeled Power (metric tons)} = \text{Total Losses Wheeled Power (MWh)} \times \text{Weighted Average Emission Factor of Wheeled Power (lbs } CO_2\text{/MWh)} \, / \, 2204.6 \text{ lbs/metric ton}$$

Equation 8.c. Determining Indirect CO_2 Emissions Associated with Direct Access

$$\textbf{Total Indirect } \mathbf{CO_2} \textbf{ Emissions from Direct Access (metric tons)} = \text{Total Losses Direct Access (MWh)} \times \text{Weighted Average Emission Factor of Direct Access (lbs } CO_2\text{/MWh)} \, / \, 2204.6 \text{ lbs/metric ton}$$

Step 4: Calculate indirect CH_4 emissions and convert to metric tons.

Once you have determined the CH_4 emission rates, multiply the MWhs purchased and the MWhs wheeled by the applicable CH_4 emission rates. Sum all CH_4 emissions and convert to metric tons by dividing by 2,204.6.

Equation 8.d. Determining Indirect CH_4 Emissions Associated with Purchased Power

$$\textbf{Total Indirect } \mathbf{CH_4} \textbf{ Emissions from Purchased Power (metric tons)} = \text{Total Losses Attributed to Purchases (MWh)} \times \text{Weighted Average Emission Factor of Purchased Power (lbs } CH_4\text{/MWh)} \, / \, 2204.6 \text{ lbs/metric ton}$$

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8.e. Determining Indirect CH_4 Emissions Associated with Wheeled Power

$$\textbf{Total Indirect } \mathbf{CH_4} \textbf{ Emissions from Wheeled Power (metric tons)} = \text{Total Losses Wheeled Power (MWh)} \times \text{Weighted Average Emission Factor of Wheeled Power (lbs } CH_4\text{/MWh)} \, / \, 2204.6 \text{ lbs/metric ton}$$

Equation 8.f. Determining Indirect CH_4 Emissions Associated Direct Access

$$\textbf{Total Indirect } \mathbf{CH_4} \textbf{ Emissions from Direct Access (metric tons)} = \text{Total Losses Direct Access (MWh)} \times \text{Weighted Average Emission Factor of Direct Access (lbs } CH_4\text{/MWh)} \, / \, 2204.6 \text{ lbs/metric ton}$$

Step 5: Calculate indirect N_2O emissions and convert to metric tons.

Once you have determined the N_2O emission rates, multiply the MWhs of purchased and wheeled power by the applicable N_2O emission rates. Sum all N_2O emissions and convert to metric tons by dividing by 2,204.6.

Equation 8.g. Determining Indirect N_2O Emissions Associated with Purchased Power

Total Indirect N_2O Emissions from Purchased Power (metric tons)	=	Total Losses Attributed to Purchases (MWh)	x	Weighted Average Emission Factor of Purchased Power (lbs N_2O/MWh)	/	2204.6 lbs/metric ton

Subtract your direct access from your wheeled power and calculate emissions from direct access separately.

Equation 8.h. Determining Indirect N_2O Emissions Associated with Wheeled Power

Total Indirect N_2O Emissions from Wheeled Power (metric tons)	=	Total Losses Wheeled Power (MWh)	x	Weighted Average Emission Factor of Wheeled Power (lbs N_2O/MWh)	/	2204.6 lbs/metric ton

Equation 8.i. Determining Indirect N_2O Emissions Associated with Direct Access

Total Indirect N_2O Emissions from Direct Access (metric tons)	=	Total Losses Direct Access (MWh)	x	Weighted Average Emission Factor of Direct Access (lbs N_2O/MWh)	/	2204.6 lbs/metric ton

Step 6: Convert GHG emissions to CO_2 equivalent and sum all subtotals.

Once you have determined all the GHG emissions, convert the CH_4 and N_2O emissions into carbon equivalents using their global warming potentials (GWPs) and sum all CO_2 emissions.

Equation 8.j. Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP

8.3 Indirect Emissions from Purchased and Wheeled Electricity

To determine your emission factor for your purchased electricity sold to end-users, you must first determine the emissions factor for your entire portfolio of purchased, wheeled power and direct access, or in other words, your entity-wide emission factor. This should be a weighted average of known and unknown resources, including:

- **Facility-specific purchases**: When power purchase agreements (PPAs) create an agreement between a specific facility and a transmission/distribution company, the purchaser should use a facility-specific emissions factor.
- **Utility-specific purchases**: If you have a PPA with an electric utility that covers a number of facilities, you should use a utility-specific emissions factor
- **Spot market purchases**: Because spot market purchases cannot be traced back to a specific source and therefore do not have a unique or reliable emission factor, you should use the spot market emission factor.

As a first step in calculating your indirect emissions, you will need to know the appropriate emission factor for your purchased and wheeled power. These may come from either source- or supplier-specific emission factors, or average power pool-specific emission factors.

As a default, you may use average power pool numbers, listed in Table 8.2, provided from U.S. EPA's eGRID database.[11]

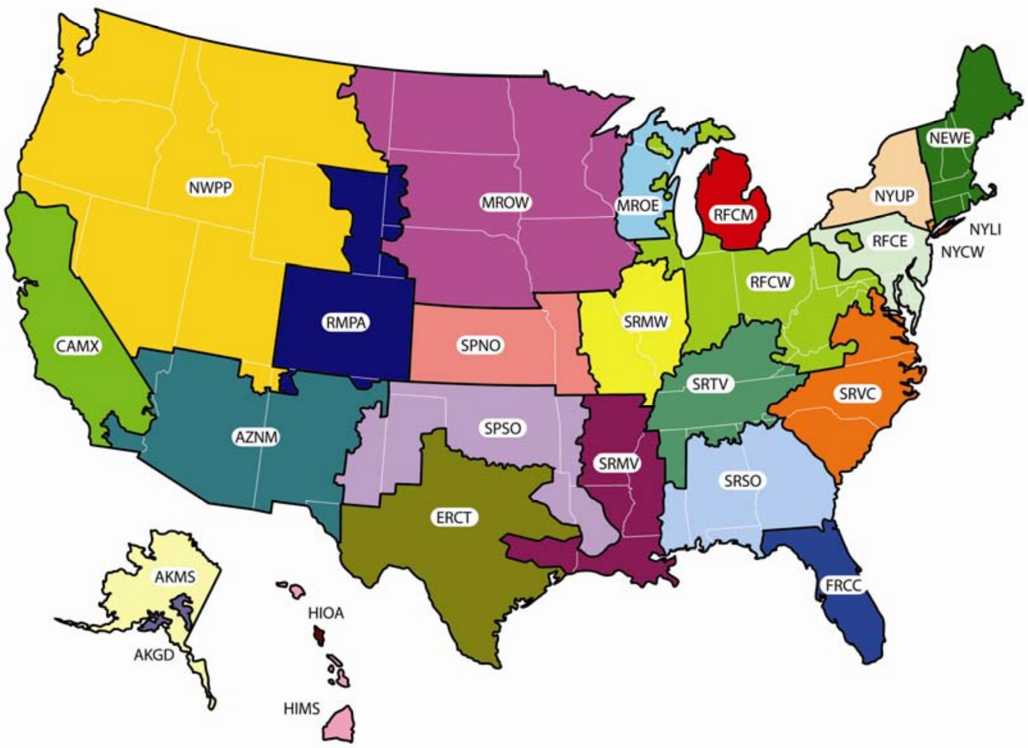

Figure 8.1. eGRID2007 Version 1.1, December 2008 Subregions.

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[11] The Emissions & Generation Resource Integrated Database (eGRID) provides information on the air quality attributes of almost all the electric power generated in the United States. eGRID provides search options including information for individual power plants, generating companies, states, and regions of the power grid. eGRID integrates 24 different federal data sources on power plants and power companies, from three different federal agencies: EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Emissions data from EPA are carefully integrated with generation data from EIA to produce useful values like pounds per megawatt-hour (lbs/MWh) of emissions, which allows direct comparison of the environmental attributes of electricity generation. eGRID also provides aggregated data to facilitate comparison by company, state, or power grid region. eGRID's data encompass more than 4,700 power plants and nearly 2,000 generating companies. eGRID also documents power flows and industry structural changes. http://www.epa.gov/cleanenergy/egrid/index.htm.

Table 8.2. eGRID Subregion Annual Average CO_2, CH_4, and N_2O Output-Based Emission Rates (Year 2005 Data).

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 (lbs/MWh)	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
AKGD	ASCC Alaska Grid	1,232.36	0.0256	0.0065
AKMS	ASCC Miscellaneous	498.86	0.0208	0.0041
AZNM	WECC Southwest	1,311.05	0.0175	0.0179
CAMX	WECC California	724.12	0.0302	0.0081
ERCT	ERCOT All	1,324.35	0.0187	0.0151
FRCC	FRCC All	1,318.57	0.0459	0.0169
HIMS	HICC Miscellaneous	1,514.92	0.3147	0.0469
HIOA	HICC Oahu	1,811.98	0.1095	0.0236
MROE	MRO East	1,834.72	0.0276	0.0304
MROW	MRO West	1,821.84	0.0280	0.0307
NEWE	NPCC New England	927.68	0.0865	0.0170
NWPP	WECC Northwest	902.24	0.0191	0.0149
NYCW	NPCC NYC/Westchester	815.45	0.0360	0.0055
NYLI	NPCC Long Island	1,536.80	0.1154	0.0181
NYUP	NPCC Upstate NY	720.80	0.0248	0.0112
RFCE	RFC East	1,139.07	0.0303	0.0187
RFCM	RFC Michigan	1,563.28	0.0339	0.0272
RFCW	RFC West	1,537.82	0.0182	0.0257
RMPA	WECC Rockies	1,883.08	0.0229	0.0288
SPNO	SPP North	1,960.94	0.0238	0.0321
SPSO	SPP South	1,658.14	0.0250	0.0226
SRMV	SERC Mississippi Valley	1,019.74	0.0243	0.0117
SRMW	SERC Midwest	1,830.51	0.0212	0.0305
SRSO	SERC South	1,489.54	0.0263	0.0255
SRTV	SERC Tennessee Valley	1,510.44	0.0201	0.0256
SRVC	SERC Virginia/Carolina	1,134.88	0.0238	0.0198

Source: eGRID2007 Version 1.1, December 2008 (Year 2005 Data).
Note: For reporting historic data from calendar years 1990 – 2006, see the GRP appendices for historic eGRID data.

8.4 Net Metering

If you have a net meter at your facility, you should report any on-site generation as direct stationary combustion. You should calculate your indirect emissions based on the portion of electricity you purchase from the grid only.

9 Industry-Specific Efficiency Metrics

This section provides guidance on determining what industry-specific metric(s) you must report to the California Registry in addition to your entity-wide absolute emissions for your stated geographic area. You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

9.1 Purpose of Reporting Industry-Specific Metrics

Normalized emissions are a ratio of your emissions compared to your output. The specific output measure depends on the nature of the organization that is reporting. Reporting normalized emissions allows trends in the carbon intensity of an activity to be gauged against a constant standard – an organization's efficiency at producing a unit of output over time. The common terms for these measures are "efficiency metrics" or "carbon intensity metrics".

In considering a power generator or electric utility's emissions, any power producer may increase its generating capacity, increase its electric output to meet growing demand, and thus increase its total GHG emissions over time. However, as it grows, the power producer may also become more efficient at generating electricity. Industry observers may also be interested in comparing the environmental performance of power producers of different sizes, which is not easy to evaluate on the basis of absolute emissions.

For the purposes of this protocol, there are two main reasons for requiring the reporting of electric power and utility industry-specific metrics:

1. To provide a basis for consistent comparison across the industry regardless of entity size
2. To track carbon intensity performance over time and complement the entity-wide absolute emissions reporting

9.2 Mandatory Efficiency Metrics

For the electric power and utility sectors the following efficiency metrics must be reported:

1. **Total Energy Electricity Generation**: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from all entity-owned or -controlled electric generating facilities (i.e. fossil fuel, renewable and nuclear) (lbs $CO_{2\text{Direct Fossil Fuel Stationary Combustion}}/MWh_{\text{Net Generated from All Energy Sources}}$).

2. **Fossil Fuel Electricity Generation**: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities (lbs $CO_{2\text{ Direct Fossil Fuel Stationary Combustion}}/MWh_{\text{ Net Generated from Fossil Fuel Sources Only}}$).

3. **Total Electricity Deliveries**: Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation and indirect CO_2 emissions from stationary fossil fuel combustion for electricity generation (e.g. CO_2 emissions from power that is purchased to meet a load-based demand) per net electricity generated by you and net electricity purchased from others for resale to end-users (lbs $CO_{2\text{ Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion}}/MWh_{\text{ Net Generated and Net Purchased from all Energy Sources}}$).

   Note that independent power producers do not deliver power to an end-user and should not report an Electricity Deliveries metric. Only utilities that purchase power to meet customer demand should report this third metric.

Emissions that you have classified as de minimis should not be included in the calculations of your efficiency metrics.

Which efficiency metric you must report depends on the nature of your business operations. More specifically:

- If your organization is vertically integrated (you own or control generation and transmission and distribution systems) you have fossil-fired generation, and you purchase electricity, you must report all three metrics.

- If your organization is vertically integrated (you own or control generation, electric transmission and distribution systems) and you purchase electricity but you have no fossil-fired generation, you must report all metrics except the fossil fuel-fired electricity generation metric.
- If you only own or control electric generation assets and do not purchase power from any other companies, you must report the two electricity generation metrics (i.e. Total Energy and Fossil Fuel).

If you have questions regarding which metrics you are required to report to the California Registry, please contact the California Registry.

If you are reporting only your California emissions, information on calculating these emissions is included below. For the generation metrics, you should include the emissions associated with your fuel combustion to generate and deliver to California at all facilities that you own, whether it is generated at facilities located inside or outside of California. For the delivery metric, you should include the emissions profile of all electricity that you generate, purchase and deliver to California.

9.3 Calculating Efficiency Metrics

To assist you in reporting these required metrics, the guidance below outlines the necessary steps to quantifying these metrics. For a discussion on optional metrics see Section 11: Optional Reporting.

For power generators, the most significant source of emissions comes from stationary fossil fuel combustion for electricity generation. For many power generators, fugitive, process, and mobile sources may all or mostly be de minimis. Thus, to maintain consistency in comparing output efficiency, these metrics necessitate the use of the CO_2 emissions associated with the combustion of fossil fuel only in calculating your efficiency.

9.3.1 Total Energy Electricity Generation

Pounds of direct CO_2 emissions from stationary fossil fuel combustion per net megawatt hour of electricity generated from all entity-owned or -controlled electric generating facilities (i.e. fossil fuel, renewable, nuclear, etc.) (lbs $CO_{2\text{Direct Fossil Fuel Stationary Combustion}}/MWh_{\text{Net Generated from All Energy Sources}}$).

If you own or control electric generating facilities, report the pounds of carbon dioxide (CO_2) emitted from stationary fossil fuel combustion to generate electricity, per net megawatt hour generated on a total energy basis (including fossil fuel, non-emitting resources such as renewable energy and nuclear power).

To calculate this metric, follow these four steps:

Step 1: Sum all of your direct CO_2 emissions from stationary fossil fuel combustion for electricity generation at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from fossil fuel combustion associated with all of the electricity that you generate and deliver to California customers.

For instance, if you own a plant in Arizona that generates 1,000,000 MWh/year, of which 80% is delivered to California, you must calculate the emissions associated with the fuel consumed to generate 800,000 MWh of electricity.

Step 2: Sum all of the net electricity generation (MWh) associated with entity-owned or -controlled electric generation.

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the net electricity generation (MWh) that you generate and deliver to California customers.

Step 3: Divide the CO_2 emissions from Step 1 by the net electricity generation from Step 2.

Step 4: Convert to lbs by multiplying by 2,204.6 lbs/metric ton.

Equation 9.a. Carbon Intensity of Entity Owned or Controlled Electricity Generation on a Total Energy Basis (lbs $CO_{2\ \text{Direct Fossil Fuel Stationary Combustion}}$/$MWh_{\text{Net Generated from All Energy Sources}}$)

Total Energy Electricity Generation Metric (lbs CO_2/MWh)	=	Direct CO_2 Emissions Associated with Stationary Fossil Fuel Combustion for Electricity Generation (metric tons CO_2)	/	Entity-Wide Electricity Generation (MWh **Net Total Energy**)	x	2204.6 lbs/metric ton

9.3.2 Fossil Fuel Electricity Generation

Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt hour of electricity generated from entity-owned or -controlled fossil-fuel fired electric generating facilities (lbs $CO_{2\ \text{Direct Fossil Fuel Stationary Combustion}}$ /$MWh_{\text{Net Generated from Fossil Fuel Sources Only}}$).

If you own or control fossil fuel-fired electric generating facilities, report your pounds of direct CO_2 emissions from stationary fossil fuel combustion to generate electricity, per net megawatt hour generated of fossil fuel-fired generation (i.e. coal, oil, natural gas, and diesel). The metric should be reported as lbs CO_2/MWh.

To calculate this metric, follow these four steps:

Step 1: Sum all of your CO_2 emissions from stationary fossil fuel combustion associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own fossil fuel-fired electricity generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from stationary fossil fuel combustion associated with all of the electricity that you generate and deliver to California customers.

For instance, if you own a plant in Arizona that generates 1,000,000 MWh/year, of which 80% is delivered to California, you must calculate the emissions associated with the fossil fuel consumed to generate 800,000 MWh of electricity.

Step 2: Sum all of the net electricity generation associated with entity-owned or -controlled fossil fuel-fired electric generation in MWh.

- If you are reporting California emissions, and you own fossil fuel-fired electricity generation outside of California and deliver a portion of that generation to California customers, you must include the net fossil fuel-fired electricity generation (MWh) that you generate and deliver to California customers.

Step 3: Divide the CO_2 emissions from Step 1 by the net fossil fuel-fired electricity generation from Step 2.

Step 4: Convert to lbs by multiplying by 2,204.6 lbs/metric ton.

Equation 9.b. Carbon Intensity of Entity Owned or Controlled Electricity Generation on a Fossil Fuel Only Basis (lbs $CO_{2\text{ Direct Fossil Fuel Stationary Combustion}}$ /$MWh_{\text{Net Generated from Fossil Fuel Sources Only}}$)

Fossil Fuel Only Electricity Generation Metric (lbs CO_2/MWh)	=	Direct CO_2Emissions Associated with Stationary Fossil Fuel Combustion in Fossil Electricity Generation(metric tons CO_2)	/	Entity-Wide Fossil Electricity Generation ($MWh_{\text{Net Fossil Generation}}$)	x	2204.6 lbs/metric ton

9.3.3 Total Electricity Deliveries

Pounds of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation and indirect CO_2 emissions from stationary fossil fuel combustion for electricity generation (e.g. emissions associated with electricity purchased from others for resale to end-users) per net electricity generated at entity owned or controlled sources and net electricity purchased from others for resale to end-users (lbs $CO_{2\text{ Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion}}$ / $MWh_{\text{Net Generated and Net Purchased from all Energy Sources}}$).

If you own or control electric generation and also purchase electricity for resale to end-users, report your lbs CO_2/MWh on a total energy basis including both net generated and net purchased power.

To calculate this metric, follow these five steps:

Step 1: Sum all of your direct CO_2 emissions from stationary fossil fuel combustion associated with the generation of electricity at entity-owned or -controlled electric generation facilities.

- If you are reporting California emissions, and you own generation outside of California and deliver a portion of that generation to California customers, you must include the CO_2 emissions from stationary fossil fuel combustion associated with all of the electricity that you generate and deliver to California customers.

Step 2: Sum all of your indirect CO_2 emissions associated with your power purchases, which are resold to end-users.

Step 3: Sum your entity-wide net electricity generation and net purchased power for delivery to end-users in MWh.

Step 4: Divide the CO_2 emissions from the sum of Step 1 and Step 2 by the net electricity generation from Step 3.

Step 5: Convert to lbs by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 9.c. Carbon Intensity of Electricity Delivered to End Use Customers in California (lbs CO_2e $_{\text{Direct Stationary Fossil Fuel Combustion and Indirect Stationary Fossil Fuel Combustion}}$ /MWh $_{\text{Net Generated and Net Purchased from all Energy Sources}}$).

Total Electricity Deliveries Metric (lbs CO_2/MWh	=	(Direct CO_2e Emissions from Stationary Fossil Fuel Combustion for Net Electricity Generation (metric tons CO_2)	+	Indirect CO_2e Emissions from Stationary Fossil Fuel Combustion Associated with Net Purchased Electricity (metric tons CO_2))	/	(Entity-Wide Net Electricity Generation (MWh $_{\text{Net Total Energy}}$)	+	Net Purchased Electricity for Resale to End-users (MWh $_{\text{Net Total Energy}}$))	x	2,204.6 lbs/metric tons

9.4 Efficiency Metrics and Combined Heat and Power

Accounting for the GHG emissions from combined heat and power (CHP) or co-generation is unique in the power/utility sectors because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the fuel and the GHG emissions between the two different energy streams is necessary. Most CHP systems capture the waste-heat from the primary electricity generating pathway and use it for climate control purposes, or to produce steam for other objectives. When the waste-heat is used directly to drive a thermal generator or to make steam that in turn drives an electric generator, these combined electricity production processes are grouped as a unit and called a combined cycle power plant. (The California Registry treats emissions resulting from combined cycle power plants as stationary combustion emissions.) The steps below show how to distinguish emissions associated with power generation from other processes that use the waste-heat from electricity production.

The three most commonly-used methods to allocate emissions of CHP plants between the electric and thermal outputs are:

1. **Efficiency method**: On the basis of the energy input used to produce the separate steam and electricity products
2. **Energy content method**: On the basis of the energy content of the output steam and electricity products
3. **Work potential method**: On the basis of the energy content of the steam and electricity product

Table 9.1. Considerations in selecting an approach to CHP emissions allocation.

Efficiency Method	• Allocates emissions according to the amount of fuel energy used to produce each final energy stream. • Assumes that conversion of fuel energy to steam energy is more efficient than converting fuel to electricity. Thus, focuses on the initial fuel-to-steam conversion process. • Actual efficiencies of heat and of power production will not be fully characterized, necessitating the use of assumed values.

Energy Content Method	• Allocates emissions according to the useful energy contained in each CHP output stream • Need information regarding the intended use of the heat energy. • Best suited where heat can be characterized as useful energy (e.g. for process or district heating). • May not be appropriate where heat used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emissions factor associated with the heat stream.
Work Potential Method	• Allocates emissions based on the useful energy represented by electric power and heat, and defines useful energy on the ability of heat to perform work. • Appropriate when heat is to be used for producing mechanical work (where much of the heat energy will not be characterized as useful energy). • May not be appropriate for systems that sell hot water because hot water cannot be used, as steam can, to perform mechanical work.

In order to insure a consistent approach in the power/utility sector to allocating GHG emissions in CHP applications, the California Registry recommends the use of the efficiency method. A default quantification methodology is provided below for this method. For more information on alternative CHP methods, see the GRP and the WRI/WBCSD GHG Protocol.[12]

9.5 Efficiency Method

For this method, emissions are allocated based on the separate efficiencies of steam and electricity production. Use the following steps to determine the share of CO_2 emissions attributable to steam and electricity production:

Step 1: Determine the total direct emissions and the total steam and electricity output for the CHP system.

Calculate total direct GHG emissions using Equation 9.d below.

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. Obtain the steam energy content values from the IAPWS-IF97 steam tables.[13]

To convert electricity output to MMBtu, sum your net electricity generation in MWhs and multiply that value by 3.415.[14]

Equation 9.d. Total CO_2 Emissions (Fuel Consumption is in MMBtu)

Total Emissions (metric tons)	**=**	Adjusted Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

[12] WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition).
[13] IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam (IAPWS-IF97), International Association for the Properties of Water and Steam. This publication replaces the previous industrial formulation, IFC-67.
[14] MWh to MMBtu conversion source: Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

Combine the steam and electricity outputs into one energy output value, expressed in the same units of energy (MMBtu) using Equation 9.e below.

Equation 9.e. Total Energy Output (in MMBtu)

Total Energy Output (MMBtu)	**=**	Steam Output (MMBtu)	+	Electricity Output (MMBtu)

Step 2: Determine the efficiencies of steam and electricity production.

Identify steam efficiencies. If actual efficiencies are not known, use default values of 80% for steam. Identify electricity efficiencies. If actual efficiencies are not known, use default value of 35% for electricity.

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

Calculate the portion of your total emissions associated with steam using the following formula:

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} * E_T \quad \text{and} \quad E_P = E_T - E_H$$

Where,

E_H	emissions allocated to steam production
H	steam output (energy)
e_H	assumed efficiency of steam production
P	delivered electricity generation (energy)
e_P	assumed efficiency of electricity generation
E_T	total direct emissions of the CHP system
E_P	emissions allocated to electricity production

Note that the use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. Nevertheless, you should be aware of the energy balance. If the constraints are not satisfied e_H and e_P can be modified until constraints are met.

Step 4: Calculate emission rates for steam and electricity production.

Divide the total CO_2 emissions from steam production (Step 3) by the total amount of steam produced to get an emission rate of pounds of carbon dioxide equivalent per thousand pounds of steam produced (lbs CO_2e/Mlbs of steam).

Equation 9.f. Emission Rate for Steam Production (lbs CO_2e/Mlbs of steam)

Emission Rate for Steam Production (lbs CO_2e/Mlbs of steam)	=	Total CO_2e Emissions from Steam Production (metric tons CO_2e)	/	Total Quantity of Steam Produced (Mlbs of steam)	x	2204.6 lbs CO_2e/metric ton

Divide the total CO_2 emissions from electricity production (Step 3) by the total amount of electricity produced to get an emission rate of pounds of carbon dioxide equivalents per megawatt hour generated (lbs CO_2e/MWh).

Equation 9.g. Emission Rate for Electricity Production (lbs CO_2e/MWh)

Emission Rate for Electricity Production (lbs CO_2e/MWh)	=	Total CO_2e Emissions from Electricity Production (metric tons CO_2e)	/	Total Quantity of Electricity Produced (MWh)	x	2204.6 lbs CO_2e/metric ton

Step 5: Estimate CO_2 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 that units used to report steam or electricity should be the same units as used to calculate the emission rates.

10 Calculating De Minimis Emissions

This section provides guidance on estimating emissions that may be de minimis in quantity. You may need information on your total annual emissions, total purchases and deliveries of electricity and/or natural gas.

For many power/utility entities the administrative effort associated with identifying, quantifying, and reporting all of their GHG emissions could be unduly burdensome and not cost-effective.

You must report at least 95% of your total emissions as part of the verifiable inventory. To reduce the reporting burden, each participant can declare up to 5% of their total emissions as de minimis. De minimis emissions must be estimated and reviewed by the verifier.

While the sources and gases that will be de minimis will vary from participant to participant, your estimates must be conservative, verifiable, and appropriately documented. You should estimate de minimis emissions using “rough upper bounds” estimates (since the amounts may be insignificant even as upper bounds). Your estimations and assumptions in calculating your de minimis emissions will need to be provided to and reviewed by your verifier.

If your operations do not change significantly from year to year, you will only need to re-calculate and have reviewed your de minimis emissions every three years. For verification purposes, records and documentation that support the de minimis calculations should be made available to the verifier.

10.1 Calculating De Minimis Emissions

The following calculations provide acceptable conservative methods for illustrating de minimis emissions for power/utility entities. These examples assume an entity that has entity-wide emissions of 3 million tonnes of CO_2e, which means that it can identify a mix of sources as de minimis up to a total of 150,000 tonnes of CO_2e.

10.1.1 Stationary Combustion Sources

In certain circumstances, power/utility entities may not have the necessary fuel use data for small combustion sources to estimate emissions according to the PUP. Where limited data exists for small combustion sources, conservative engineering estimates are an acceptable method for quantifying GHG emissions and illustrating whether these emissions are de minimis.

Estimate your direct CO_2 emissions from stationary combustion sources using the following process:

1. Identify the operating parameters of the source
2. Identify the appropriate emission factor based on fuels combusted in the source
3. Calculate CO_2 emissions and convert to metric tons

Each of these steps is described in greater detail below.

Step 1: Identify the operating parameters of the source.

Use company records to identify the capacity of the piece of equipment along with conservative assumptions about operating hours and fuel use to calculate emissions.

Step 2: Identify the appropriate emission factor based on fuel combusted in the source.

Use the default emission factors provided in Section 5 (Stationary Combustion) to calculate CO_2 emissions associated with the source.

Step 3: Calculate CO_2 emissions and convert to metric tons.

Use the default emission factors identified to calculate CO_2 emissions associated with the source and divide the number of lbs CO_2 obtained by 2,204.6 lbs/metric ton to obtain metric tons of CO_2 produced.

Example 10.1. Calculating De Minimis Emissions from Stationary Combustion Sources

Company A has an oil-fired auxiliary boiler (Boiler X) with a nameplate capacity of 2 MMBtu/hr. The boiler has no fuel meter. The boiler is used only for plant startups and quarterly operational checks.

Estimate the emissions from Boiler X:

Step 1: Identify the operating parameters of the source.
In a typical year no more than two or three plant startups occur. Quarterly checks and startups are assumed to last for five hours with Boiler X operating at full capacity. To achieve a conservative estimate of emissions from Boiler X, assume five plant startups and four quarterly operational checks for a total of nine operating times or 45 hours total.

45 hours x 2 MMBtu/hr = 90 MMBtu

Step 2: Identify the appropriate emission factor based on fuel combusted in the source.
Oil-fired auxiliary boiler with nameplate capacity of 2 MMBtu/hour = 78.80 kg CO_2/MMBtu

Step 3: Calculate CO_2 emissions and convert to metric tons.
90 MMBtu x 78.80 kg CO_2/MMBtu x 0.001 metric tons/kg = 7.092 metric tons CO_2

10.1.2 Fugitive CH_4 Emissions from Fuel Handling and Storage

Handling and storage of some fuels may be a source of fugitive CH_4 emissions. For instance, different types of coals desorb methane at different rates, but since coal is usually removed from a mine within hours or days of being mined, some methane remains and is liberated from the coal during handling operations. Fugitive emissions such as these are likely de minimis for most entities.

At this time, there is no guidance provided in the PUP to complete a de minimis calculation for fugitive emissions from biomass fuel use and handling. However, in the future a method may be identified based on guidance from the California Registry Forest Protocol.

A methodology is presented below to help you conservatively estimate fugitive CH_4 emissions associated with coal handling and storage. This method uses U.S. EPA-established emission factors for coal that encompass all post-mining activities, including storage in piles at the utilities.

Estimate your fugitive CH_4 emissions using the following process:

1. Identify the total tons of coal purchased
2. Identify the appropriate emission factor based on coal origin
3. Calculate fugitive CH_4 emissions and convert to metric tons
4. Convert CH_4 emissions to CO_2 equivalent and sum all subtotals

Each of these steps is described in greater detail below.

Step 1: Identify the total tons of coal purchased.

Consult purchase records to identify the total quantity of coal purchases that originate from underground and surface mines.

Step 2: Identify the appropriate emission factor based on coal origin.

Use the default emission factors noted in Table 10.1 below to calculate fugitive methane emissions associated with the fuel handling and storage of the coal.

Table 10.1. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors CH_4 ft^3 / ton**	**Underground Post-Mining Factors CH_4 ft^3 / ton**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: U.S. EPA Coal Bed Methane Emissions Estimates Database, *Fugitive Emission Factors for Coal Storage*, Table 10. *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005*, April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH4 Emission Factors (ft3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Step 3: Calculate fugitive CH_4 emissions and convert to metric tons.

Convert from standard cubic feet of methane to lbs of methane by multiplying by 0.04228 lbs CH_4 per standard cubic feet of CH_4. Divide the number of lbs CH_4 obtained by 2,204.6 lbs/metric ton to obtain metric tons of CH_4 produced.

Equation 10.a. Determining Total Annual Fugitive Methane Emissions

Total Fugitive Emissions of CH_4 (metric tons)	=	Fugitive Methane Emissions (ft^3)	x	0.04228 lbs CH_4/ft^3	/	2,204.6 lbs/ metric ton

Step 4: Convert CH_4 emissions to CO_2 equivalent and sum all subtotals.

To incorporate and evaluate non-CO_2 gases in your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO_2 equivalent. To do this, multiply the emissions in units of mass by the GWP of CH_4. If non-CO_2 gases are de minimis when converted to CO_2e, you can assign them as de minimis when reporting them to the California Registry. Also, you are not required to report non-CO_2 gases until the fourth year that you report emissions to the California Registry.

Equation 10.b. Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e	**=**	Metric Tons of GHG	x	GWP

Example 10.2. Calculating De Minimis Emissions from Coal Piles

In a typical year, Company A purchases 1 million tons of coal.

To achieve a conservative estimate of fugitive emissions from coal purchases, Company A assumes that all the coal originates from underground mines.

Step 1: Identify total tons of coal purchased: 1 million tons

Step 2: Identify the appropriate emission factor based on coal origin and multiply by total tons of coal purchased:

Coal Basin	**States**	**Underground Post-Mining Factor** CH_4 ft^3/ton
Central Appalachia (WV)	Tennessee, West Virginia South	44.5

1,000,000 tons x 44.5 CH_4 ft^3/ton = 44,500,000 ft^3 CH_4

Step 3: Calculate fugitive CH_4 emissions and convert to metric tons.

Equation 10.a. Determining Total Annual Fugitive Methane Emissions

853 metric tons (CH_4)	**=**	44,500,000 ft^3 Fugitive Methane Emissions	x	0.04228 lbs CH_4/ft^3	/	2,204.6 lbs/ metric ton

Step 4: Calculate total Global Warming Potential

Equation 10.b. Converting Mass Estimates to Carbon Dioxide Equivalent

17,913 Metric Tons of CO_2e	**=**	853 metric tons CH_4	x	21 (GWP)

10.2 Selecting De Minimis Sources

Once you have estimated all of the sources you believe are de minimis, you need to determine if they are indeed less than 5% of your total emissions.

Step 1: Total emissions from all estimated de minimis sources.

Step 2: Divide your total emissions by your total estimated de minimis emissions.
If the total is less than 5%, all of your estimated emissions may be classified as de minimis. If your total is greater than 5%, you must assess which emissions you will obtain the necessary information to calculate, report and have verified. You should classify your sources from largest to smallest, and report the emissions from the largest of the de minimis sources.

11 Optional Reporting

In order to verify an emissions report with the California Registry, some categories of emissions are required. These include emissions from direct sources such as stationary combustion, mobile combustion, fugitive emissions, and process emissions. These also include indirect emissions associated with electricity, steam, and heating and cooling that are purchased and consumed. For the purposes of this program, all other categories of information are considered optional. Because there are no protocols governing optional reporting, the optional reporting information is not eligible for verification within the California Registry. The State of California will only back verified information reported to the California Registry.

The California Registry encourages its participants to provide additional information, e.g. emissions associated with product shipping, employee commuting and business travel, etc. Measuring such kinds of information will help each participant understand the full impact of their business activities. You may also want to include references to your organization’s environmental goals, policies, programs, and performance. This information can showcase your environmental efforts, including emission reduction projects. Also, you can provide links to external sources to allow viewers to learn more about your environmental programs. This optional reporting section allows power/utility entities to create a public record of other activities that may complement the emissions inventory.

This section outlines some limited guidance for optional reporting areas relevant to electric power generators and electric utilities to serve as a starting point for your effort to identify and calculate emissions from other activities of your organization.

11.1 Other Reporting

Other activities that you may choose to report include:

- **Indirect emissions from extraction, production, and transportation of fuels used for generation of electricity, heat, or steam.** This includes the upstream emissions associated with the extraction and production of fuels used to generate electricity. Examples include emissions from mining of coal, and extraction of natural gas.

- **Purchases and sales of tradable renewable certificates (TRC)**. At a minimum, you should report the quantity of TRCs purchased or sold in a given year, the purpose(s) of the purchase and sales, and the geographic origin of the TRCs. You should also identify the other registries and/or regulatory agencies to which you have reported this information.

- **Annual energy efficiency savings.** You should report megawatts of peak load saved and total electricity saved annually in megawatt-hours. You should also report the reason for undertaking the energy efficiency programs (regulatory requirements, demand response, voluntary, etc.), and to which other registries and/or regulatory agencies you have reported this information.

- **Purchases and sales of GHG emission offset projects.** At a minimum, you should report the type of project(s) and the quantity of emission reductions. You should also report the terms of the purchase and/or sale and to which other registries and/or regulatory agencies you have reported this information.

- **Contractual agreements assigning liability.** You should report the details of the specific contractual agreements including the parties involved, the scope of the agreement, and the duration of the agreement. You should also report to which other registries and/or regulatory agencies you have reported this information.

11.2 Optional Metrics

You may also report optional efficiency metrics as part of your annual GHG emissions report to the California Registry to highlight aspects of your environmental performance. The following efficiency metrics may be reported along with entity-wide emissions.

- **Energy Output**. Pounds of direct CO_2 equivalent emissions per million British thermal units of energy output from all entity-owned or -controlled assets and facilities (lbs CO_2e_{Direct}/MMBtu $_{Direct}$).
- **Natural Gas Deliveries**. Pounds of direct carbon dioxide equivalent emissions per therm of natural gas delivered from entity-owned or -controlled natural gas transmission, storage and/or distribution assets (lbs CO_2e_{Direct}/Therm).
- **Fuel or Facility**. If you own or control electric generating facilities you may report pounds of carbon dioxide equivalent per megawatt hour generated (lbs CO_2e/MWh) on a fuel-specific basis or facility-specific basis.
- **Electricity by Customer Type**. If you own or control electric transmission & distribution assets you may report lbs CO_2e/customer by customer type (residential, commercial, industrial).
- **Natural Gas by Customer Type**. If you own or control natural gas transmission & distribution assets you may report lbs CO_2e/customer by customer type (residential, commercial, industrial).

If your organization is vertically integrated (you own or control generation, transmission, and distribution systems) such as investor-owned utilities, then you may report any combination of the metrics outlined above.

Guidance is provided, for your reference, on calculating two of these optional metrics. These methodologies are provided for your information only. However, these metrics are not currently eligible for verification under the California Registry program.

11.2.1 Energy Output: Pounds of direct CO_2e emissions per million British thermal units of energy output from all entity-owned or controlled assets and facilities (lbs CO_2e_{Direct}/MMBtu $_{Direct}$)

All power/utility entities reporting to the California Registry must report this entity-wide metric, which incorporates all of your required direct emissions including:

- stationary combustion from the onsite production of heat, steam, or electricity owned or controlled by your organization

- fugitive leaks or venting from operations owned or controlled by your organization including natural gas systems, electricity transmission and/or distribution systems, air conditioning and refrigeration systems, and fire suppression equipment
- processes such as emission control technologies and other activities that are owned or controlled by your organization
- mobile combustion from non-fixed sources that are owned or controlled by your organization

To calculate this entity-wide metric, follow these four steps:

Step 1: Sum all of your entity-wide direct CO_2e emissions. Include all the direct emissions from stationary and mobile combustion, fugitive leaks and venting, and processes.

Step 2: Sum your total natural gas deliveries in therms and convert to million British thermal units (MMBtu) by multiplying by 0.1.[15]

Step 3: Sum your net electricity generation in MWhs and convert to MMBtu by multiplying by 3.412.[16]

Step 4: Sum total entity-wide MMBtu and divide the direct CO_2e emissions from Step 1 by the entity-wide MMBtu.

Step 5: Convert to lbs by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 11.a. Entity-wide Carbon Intensity Metric (lbs CO_2e_{Direct} / MMBtu)

$$\textbf{Carbon Intensity Metric – Entity-wide (lbs } \mathbf{CO_2e}\textbf{/MMBtu)} = \text{Entity-wide Direct } CO_2e \text{ Emissions (metric tons } CO_2e) \,/\, \left[\text{Natural Gas Deliveries (MMBtu)} + \text{Net Electricity Generation (MMBtu)} \right] \times \text{2,204.6 lbs/ metric ton}$$

11.2.2 Natural Gas Deliveries: Pounds of direct CO_2e emissions per therm of natural gas delivered from entity-owned or -controlled natural gas transmission, storage and/or distribution assets (lbs CO_2e_{Direct}/therm)

If you own or control natural gas transmission, storage and/or distribution assets you shall report lbs CO_2e/therm of natural gas delivered to end-users.[17]

To calculate this metric, follow these four steps:

Step 1: Sum all of your direct CO_2e emissions from your natural gas transmission, storage, and/or distribution system. Include all the direct emissions associated with the physical natural gas system you own or control including stationary combustion activities, fugitive emissions of CH_4 and CO_2, and vented emissions.

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[15] Therm to MMBtu conversion source – Energy Information Administration (EIA), *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.
[16] MWh to MMBtu conversion source – Same as above.
[17] A therm is 100,000 Btus and is the unit most often used by distribution companies. One decatherm (Dth) is 10 therms, or one MMBtu (one million Btu).

Step 2: Sum your total natural gas deliveries to end-users in therms.

Step 3: Divide the CO_2e emissions from Step 1 by the therms of natural gas deliveries to end-users from Step 2.

Step 4: Convert to lbs by multiplying by 2,204.6 lbs/metric ton. The equation is illustrated below.

Equation 11.b. Carbon Intensity of Natural Gas Delivery (lbs CO_2e_{Direct} / Therm)

Carbon Intensity Metric – Natural Gas (lbs CO_2e/Therm)	=	Direct CO_2e Emissions Associated with Natural Gas System (metric tons CO_2e)	/	Natural Gas Deliveries to End Use Customers (Therm)	x	2,204.6 lbs/metric tons)

12 Glossary of Terms

Boiler	A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.
Bulk Electric System	A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.
Bulk Transmission	A functional or voltage classification relating to the higher voltage portion of the transmission system.
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.
Co-generation	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Combined Cycle	An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.
Continuous Emissions Monitoring Systems	CEMS is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. CEMS include: • An SO_2 pollutant concentration monitor • A NO_x pollutant concentration monitor • A volumetric flow monitor • An opacity monitor • A diluent gas (O_2 or CO_2) monitor • A computer-based data acquisition and handling system (DAHS) for recording and performing calculations with the data
Demand	The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load.
Demand-Side Management	The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of

	electricity use.
De minimis	A quantity of GHG emissions from one or more sources, for one or more gases, which, when summed equal less than 5% of an organization's total emissions.
Direct monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic sampling.
Distribution System	The low voltage system of power lines, poles, substations and transformers, directly connected to homes and businesses. Your Distribution Company is the electric utility that delivers electricity to your home or business over these wires. The utility will read your meter, maintain local wires and poles and restore your power in the event of an outage.
Electric Plant (Physical)	A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.
Electric System Losses	Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.
Electric Utility	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. Types of Electric Utilities include investor-owned, cooperatively owned, and government-owned (federal agency, crown corporation, state, provincials, municipals, and public power districts).
Electrical Energy	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Federal Energy Regulatory Commission (FERC)	A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline verification.
Fuel Totalizer	A meter that sums the volume or mass of fuel used (rather than the flow rate of fuel).
Fugitive Emissions	Unintended leaks of gas from the processing, storage, transmission, and/or transportation of fossil fuels.
Generation (Electricity)	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).
Geothermal Plant	A plant with steam turbines powered by either steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the

	surface of the earth. The energy is extracted by drilling and/or pumping.
Gross Generation	The electrical output at the terminals of the generator, usually expressed in megawatts (MW).
Heating value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating values (HHVs), used in the U.S. and Canada, and lower heating values, used in all other countries.
Independent Power Producers (IPP)	As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term may include, but is not limited to, cogenerators and small power producers and other nonutility electricity producers, such as exempt wholesale generators who sell electricity.
Kilowatt-Hour	A standard unit of measure of electrical energy One kilowatt-hour is equal to 1,000 watt-hours. The total number of kilowatt-hours charged to your bill is determined by your electricity use. For example, if you used a 100-watt light bulb for 10 hours, you would be billed for one kilowatt-hour (100 watts x 10 hours= 1,000 watt-hours). The average home in the United States uses 750 kWh/ month.
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.
Load	An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.
Mains	Physical system through which liquid or gaseous fuels are transported.
Megawatt-Hour	One thousand kilowatt-hours or 1 million watt-hours.
Metering	The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.
Municipal Utility	A municipal utility is a non-profit utility that is owned and operated by the community it serves.
Net Capacity	The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
Net Energy for Load	The electrical energy requirements of an electric system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for

	storage at energy storage facilities.
Net Generation	Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW) or megawatt hours (MWh).
North American Electric Reliability Council (NERC)	A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry — investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid- Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).
Pipeline (Natural Gas)	A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use.
Pipeline Fuel (Natural Gas)	Gas consumed in the operation of pipelines, primarily in compressors.
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.
Qualifying Facility (QF)	A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by FERC pursuant to PURPA (See CFR, Title 18, Part 292).
Renewable Energy	Energy drawn from a source that is infinite or is replenished through natural processes. Such sources include the sun, wind, heat from the earth's core, biomass, and moving water.
Renewable Power	A power source other than a conventional power source, defined as power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology…is employed in the production of such power.
Spot Purchases	A single shipment of fuel or volumes of fuel, purchased for immediate delivery or within one year. Spot purchases are often made by a user to fulfill a certain portion of energy

	requirements, to meet unanticipated energy needs, or to take advantage of low fuel prices.
Stocks	A supply of fuel accumulated for future use. This includes, but is not limited to, coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.
Storage	Energy transferred from one entity to another entity that has the ability to conserve the energy (i.e. stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more usable to the original supplying entity.
Substation	A facility for switching electrical elements, transforming voltage, regulating power, or metering.
Transformer	An electrical device for changing the voltage of alternating current.
Transmission (Electric)	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock (aquifer).
Vented Emissions	Releases to the atmosphere as a result of the process or equipment design or operational practices.
Wheeling Service	The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.
Wholesale Sales	Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

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Appendix A EPA Method For Estimating SF_6 Emissions from Electrical Equipment Used by Utilities

This worksheet is based on the mass-balance method. The mass-balance method works by tracking and systematically accounting for all company uses of SF_6 during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D) and a final total (E).

A. Decrease in Inventory. This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The decrease in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. Purchases/Acquisitions of SF_6. This is the sum of all the SF_6 acquired from other entities during the year either in storage containers or in equipment.

C. Sales/Disbursements of SF_6. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. Increase in Total Nameplate Capacity of Equipment. This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. The Increase in Total Nameplate Capacity of Equipment will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. Total Annual Emissions. This is the total amount of SF_6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF_6 and in metric tons of CO_2-equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF_6 emitted. Because SF_6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF_6 is equivalent to nearly 11 tonnes of carbon dioxide.

F. Emission Rate (optional). By providing the total nameplate capacity of <u>all</u> the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year). The emission rate is equal to the total annual emissions divided by the total nameplate capacity.

Change in Inventory (SF_6 contained in cylinders, <u>not</u> electrical equipment)		
Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Change in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Change in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of <u>new</u> equipment		
11. Total nameplate capacity (proper full charge) of <u>retired</u> or <u>sold</u> equipment		
D. Change in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	Tonnes CO_2 equiv. (lbs.SF_6x23,900/2205)
E. Total Emissions (A+B-C-D)	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	