Greenhouse Gas Inventory Guidance

Indirect Emissions from Purchased Electricity

United States
Environmental Protection
Agency

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

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

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Section 1: Introduction

Indirect emissions are those that result from an organization's activities but are actually emitted from sources owned by other entities. Scope 2 emissions are indirect emissions that occur through the use of purchased electricity, steam, heat, or cooling. Steam, heat (in the form of hot water), and cooling (in the form of chilled water) can be delivered to an organization's facilities through a localized grid called a district energy system or through a direct line connection. The term "electricity" will be used in this guidance to refer to purchased electricity, steam, heat, or cooling, except when addressing issues specific to each energy source, such as emission factors.

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are emitted to the atmosphere as fuels are burned to produce heat and power. Therefore, activities that use purchased electricity indirectly cause emissions of greenhouse gases (GHG). The resulting emissions depend on the amount of energy used and the mix of fuel that goes into producing this electricity. This document presents guidance on calculating scope 2 indirect emissions resulting from these sources. Emissions associated with on-site generation of electricity in equipment owned and operated by the organization are direct scope 1 emissions and are not addressed in this document.

The GHG Protocol Scope 2 Guidance provides a comprehensive discussion of issues related to quantification and reporting of scope 2 emissions, and organizations are encouraged to consult that guidance. This document is aligned with the principles and methodologies defined in the GHG Protocol Scope 2 Guidance. However, it does not attempt to address all scope 2 issues. Guidance for quantifying two scope 2 emissions totals, using a location-based method and a market-based method, is included in this document. The organization should quantify and report both totals in its GHG inventory. The location-based method considers average emission factors for the electricity grids that provide electricity. The market-based method considers contractual arrangements under which the organization procures power from specific sources, such as renewable energy.

GHG reduction goals that include scope 2 emissions can be based on either the location-based or market-based method. If the organization reports a combined scope 1 and scope 2 GHG inventory, the organization may report two inventory totals based on both methods, or they may report the total based on only one method, provided that is the same method used for their goal. The organization must specify which method is used for goal setting and for a scope 1 and scope 2 combined inventory. If scope 2 base year emissions were calculated using different methodologies than those specified in this guidance, base year emissions should be recalculated to be consistent with this guidance and include both location-based and market-based emissions, so that emissions are comparable over time.

EPA encourages organizations to use renewable energy as a way to reduce the environmental impacts associated with the electricity they purchase. Organizations can reduce their market-based scope 2 emissions by purchasing renewable energy, or "green power." They can do this by choosing a differentiated electricity product from their utility or electricity supplier, by contracting directly with a renewable energy generator (if the regulatory rules allow), or by purchasing unbundled renewable energy certificates (RECs). In any case, the RECs must be acquired and retired. This document provides guidance on quantifying the impact of renewable energy purchases based on an emission factor approach using a hierarchy of possible emission factors, rather than based on avoided emissions.[1]

[1] The GHG Protocol Scope 2 Guidance discusses approaches for optional reporting of avoided emissions from low-carbon electricity purchases, which can be done separately from the organization's GHG inventory.

1.1 Greenhouse Gases Included

The greenhouse gases CO_2, CH_4, and N_2O are emitted during the combustion of fuels to generate electricity. In the U.S., CO_2 emissions represent approximately 99 percent of the total CO_2 equivalent GHG emissions from fuels combusted for electricity production. CH_4 and N_2O together represent approximately one percent of the total CO_2 equivalent emissions from the same sources.[2]

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

[2] See Table 3-7 of U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021, EPA 430-R-23-002, April 2023 https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

Section 2: Calculating Emissions

This section presents guidance to calculate GHG emissions from purchased electricity, steam, heat, and cooling. This guidance is applicable to calculation of emissions in both the location-based and market-based methods. It is recommended that organizations calculate emissions for each of their facilities separately, as opposed to aggregating multiple facilities to calculate emissions. This increases the accuracy and credibility of the inventory.

2.1 Calculation Steps

For both the location-based and market-based methods, emissions are calculated by multiplying the purchased electricity during the reporting year by appropriate emission factors. The steps involved with calculating emissions from consumption of purchased electricity are shown below. The same approach is applicable to steam, heat, and cooling.

Step 1: Determine the amount of electricity purchased.
See Section 3.1 for a discussion of possible data sources.

Step 2: Determine emission factors.
See Section 3.2 for guidance on selecting appropriate emission factors for the location-based and market-based methods.

Step 3: Calculate emissions.
Use Equation 1 to calculate the emissions of CO_2, CH_4, and N_2O.

Equation 1:

Emissions = Electricity x EF
Where:

Emissions = Mass of CO_2, CH_4, or N_2O emitted
Electricity = Quantity of electricity purchased
EF = CO_2, CH_4, or N_2O emission factor

Multiply the emissions of CH_4 and N_2O by the respective global warming potential (GWP) to calculate CO_2 equivalent emissions. For GWP values, see the latest release of the EPA's GHG Emission Factors Hub, which is discussed further in Section 3.3.1. Sum the CO_2 equivalent emissions from CH_4 and N_2O with the emissions of CO_2 to calculate the total CO_2 equivalent (CO_2e) emissions.

2.2 Allocating Emissions from Combined Heat and Power

In a cogeneration or combined heat and power (CHP) plant, the same fuel supply is used to generate electricity together with steam, heat, and/or cooling. The emissions from the CHP plant are based on type of fuel used and must be allocated proportionally to the each of the various energy outputs. It is not appropriate to assign all the emissions to only one of the outputs. For more description of available allocation methods, organizations may refer to the GHG Protocol's guidance Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant.[3]

[3] Greenhouse Gas Protocol. Allocation of Emissions from a Combined Heat and Power (CHP) Plant. September 2006. Guidance: https://ghgprotocol.org/sites/default/files/2023-03/CHP_guidance_v1.0.pdf. Worksheet: https://ghgprotocol.org/sites/default/files/2023-03/CHP_tool_v1.0.xls.

Section 3: Choice of Activity Data and Emission Factors

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

3.1 Activity Data Sources

To quantify scope 2 emissions, the activity data needed are the amount of electricity that is purchased during the reporting year. Utility bills or other purchase records can be used to determine the amount of electricity purchased. This information on the electricity entering the organization's facility is considered the best type of activity data as opposed to sub-metering data from within the facility, which may be incomplete.

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

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

If electricity is delivered through a grid, the amount of electricity generated to deliver this purchased electricity is usually more than what is purchased, due to transmission and distribution losses. It is the responsibility of the owner of the transmission and distribution system to report scope 2 emissions from transmission and distribution losses. Therefore, the scope 2 emissions for end-users only include the emissions associated with the amount of electricity they purchase and consume within their facilities. For end-users, transmission and distribution losses are included in Scope 3, Category 3, Fuel- and energy-related activities. For more information on quantification of these emissions, see the EPA's Scope 3 Inventory Guidance page.

If an organization operates fully or partial electric vehicles, the electricity used to charge electric vehicles at its facilities will already be included in the electricity consumption for those facilities, and no additional action is necessary to include these vehicles' electricity use in its scope 2 emissions. If an organization's electric vehicles are charged elsewhere (e.g., at public charging stations or employees' homes), this electricity will not be included in the organization's facility electricity use. It represents another source of purchased electricity to be included in scope 2 emissions. The most accurate method of determining the amount of electricity used, and therefore the preferred method, is to gather data from charging records. If electricity is purchased at commercial charging stations, charging receipts may be obtained from the vehicle operators, or through records from centralized charging card services. If vehicles are charged at employees' homes, the charging equipment or the vehicle itself may record the amount of electricity used for charging.

The organization's facilities may have on-site generation systems that produce electricity to meet the demand of that facility. These systems may be owned and operated by the reporting organization or by an external party. The ownership determines the appropriate means of accounting for emissions from these on-site systems.

For on-site generation that is owned by the reporting organization, the emissions from the system are direct scope 1 emissions. As such, the quantity of electricity generated and consumed on-site is not included in the activity data used to quantify scope 2 emissions from purchased electricity. If the organization sells electricity from its owned on-site system to another organization directly or to the grid, 1) the quantity of fuel used to generate the sold electricity should not be deducted from total fuel use when quantifying scope 1 emissions, and 2) the quantity of sold electricity should not be deducted from the reporting organization's total electricity purchases when quantifying scope 2 emissions.

If the on-site generation is not owned by the organization, the electricity used on-site should be treated as purchased electricity in scope 2. This is an example of a direct-line connection between the reporting organization and the electricity generating source, which is discussed further in Section 3.3.

3.2 Activity Data Units

The units of measure in which activity data are reported on utility bills or other purchase records can vary between electricity, steam, heat, and cooling. For electricity, heat, and cooling, activity data are typically reported in energy units. For electricity, kilowatt-hours (kWh) or megawatt-hours (MWh) are most common. Heat and cooling can be reported in a variety of energy units. A common unit of measure for cooling is a ton-hour, which equals 12,000 Btu.

Steam may be reported in energy units or in mass units. Because steam emission factors are expressed per unit of energy, activity data in mass units should be converted to energy units. The steam's pressure and temperature can be used with standard steam tables to calculate the steam's energy value. In some cases, not all of the energy entering an organization's facility as steam is used in the facility's processes. Some of the energy could be returned to the steam supplier as condensate. If this is the case, the appropriate energy value selected from the steam table should reflect this.

It is possible that organizations may only know the cost of electricity, steam, heat or cooling purchased. This is the least accurate method of determining consumption and is not recommended for GHG reporting. If cost is the only information initially available, it is recommended that organization contact their supplier to request data in energy units (or mass for steam). If no other information is available, organizations should use energy prices to convert the amount spent to energy or mass units, and should document the prices used. Price varies widely for these energy sources, especially over the geographic area and timeframe typically established for reporting GHG emissions.

3.3 Emission Factors

Emission factors are necessary to calculate the emissions attributable to electricity, steam, heat, and cooling purchases. Emission factors reflect the renewable or fossil energy resource(s) used and the efficiency of converting input energy into useful energy output. Emission factors should be chosen based on the guidance below. Scope 2 emissions are generated from sources owned and operated by other entities, and include indirect emissions from generation only, meaning the emissions that occur through the use of purchased electricity, steam, heat, or cooling and are quantified at the point of generation. Therefore, emission factors for electricity, steam, heat, or cooling should not include the impact of transmission and distribution losses, nor emissions from fuel extraction or other activities upstream of the generation facility.

Organizations should calculate and report scope 2 emissions using two methods: one using location-based emission factors, and one using market-based emission factors. Both results should be clearly labeled according to the method used.

3.3.1 Location-Based Electricity Emission Factors

The location-based method considers average emission factors for the electricity grids that provide electricity. The following are the types of location-based emission factors available, listed in order of preference based on the precision of the factors.

1. Direct Line Emission Factor

An organization may purchase electricity through a direct line connection (as opposed to an electricity distribution grid) from a known electric generation source, such as a generation facility located at a central plant of a campus or other nearby building, or an on-site generation facility that is owned or operated by another organization. In such a case, the emission factor specific to that generation facility is preferred for calculating emissions in the location-based method. If energy attribute certificates from the generation facility are sold to a party other than the electricity purchaser, see Section 3.3.7. If the generation facility is a CHP plant, refer to Section 2.2 for guidance.

In cases where an organization purchases electricity both through a direct line connection and from the grid, the organization should calculate the indirect emissions separately for the two sources, using a direct line emission factor for the portion of the electricity purchased from the specific known source, and one of the grid average factors described below for the portion of the electricity purchased from the grid.

2. Regional Emission Factor

If an organization purchases electricity that is delivered through a grid, the organization should use published emission factors based on the geographic location of each of its facilities, corresponding to the average emission factor of generation facilities supplying power to the grid. It is recommended to use regional or subnational emission factors, representing a grid distribution area.

Regional factors are available for several countries through national governments or other sources. For operations in the U.S., the recommended regional factors are the total output subregion grid factors published by the EPA's Emission & Generation Resource Integrated Database (eGRID)[4]. The total output factors represent average emission factors for all plants generating electricity for the grid, including baseload, intermediate, and peaking units. An eGRID subregion represents a portion of the U.S. power grid that is contained within a single North American Electric Reliability Council (NERC) region. Most of eGRID's subregions consist of one or more power control areas (PCAs). eGRID subregions generally represent sections of the power grid that have similar emissions and resource mix characteristics and may be partially isolated by transmission constraints.

EPA publishes a GHG Emission Factors Hub that contains the most recent eGRID subregion emission factors. There may be a delay between the release of a new version of eGRID and the update of the Emission Factors Hub. The most recent version of eGRID, along with supporting documentation and resources, is available at https://www.epa.gov/egrid.

[4] The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of all electric power generated in the United States. eGRID provides information on air pollutant emissions and resource mix for individual power plants, generating companies, states, and regions of the power grid. eGRID is available at https://www.epa.gov/egrid.

To determine in which eGRID subregion an organization's facilities are located, they can use the Power Profiler Tool. This tool allows users to enter their facility zip codes and utility names to identify the appropriate eGRID subregions.

3. National Emission Factor

If regional factors are not available, national average emission factors can be used, such as those published by national governments or by the International Energy Agency (IEA).

3.3.2 Market-Based Electricity Emission Factors

The market-based method considers contractual arrangements under which the organization procures power from specific sources, such as fossil, renewable, or other generation facilities. Market-based emission factors reflect these arrangements. The following are the types of market-based emission factors available, listed in order of preference based on the precision of the factors.

1. Energy Attribute Certificates

If an energy attribute certificate carries with it an emission factor, that factor can be used to quantify emissions in the market-based method. Examples are renewable energy certificates (RECs) or Guarantees of Origin (GOs) in Europe. Refer to the quality criteria in Section 4 to ensure that an emission factor can be claimed based on the certificate. The emission factor is based on the specific source that the certificate represents, regardless of the energy resource used. Typically, these certificates represent renewable energy and may have an emission factor of zero, but they may in some cases have a non-zero emission factor (e.g., if there is a fossil-fuel or biomass generation component).

2. Contracts

An organization may have a contract, such as a power purchase agreement (PPA), to purchase electricity from a specified generating facility, which may be located at the organization's facility, at a nearby location with a direct line connection to the organization, or located remotely. If there are no certificates associated with this generation, the contract itself carries the emission factor associated with the generation facility, regardless of the energy resource used. Refer to the quality criteria in Section 4 to ensure that an emission factor can be claimed based on the contract. If certificates are issued to the generating facility, the emission factor is conveyed by the certificates, rather than the contract. If the certificates are bundled with the contract, the purchaser can claim the emission factor. If the certificates are sold to another entity, the purchaser cannot make that claim, and the energy should be assigned the residual mix factor if available, or the regional or national factor.

3. Supplier-Specific Emission Factor

An electricity supplier, such as a regulated utility or a deregulated supplier, may provide information to its customers on the emission factor associated with its electricity product. The product may be a standard product or a differentiated product. To be used in the market-based method, the emission factor must include all the electricity delivered by the supplier, including electricity it generates as well as electricity it purchases from others. An example of a factor that should not be used is a supplier emission factor that only includes generation facilities owned by the supplier, which does not represent the full set of generation facilities supplying the delivered electricity

4. Residual Mix Factor

A residual mix emission factor represents the emissions and generation that remain after certificates, contracts, and supplier-specific factors have been claimed and removed from the calculation. It can be a regional or national factor. Residual mix factors are the preferred market-based default emission factors for any of an organization's electricity for which it cannot apply one of the more-preferred emission factors above. This is because the use of residual mix emission factors avoids double counting of the emissions attributes of contractual instruments. Currently, residual mix factors are not widely available. For example, they are not available across the U.S., though some regional certificate tracking systems report a residual mix factor. Development of residual mix factors for the U.S. is under consideration. Organizations must disclose the lack of residual mix factors as part of their scope 2 reporting. As with other emission factors, organizations are encouraged to check for available residual mix factors each year when they complete their GHG inventory.

5. Regional Emission Factor

If residual mix factors are not available, organizations can use a regional grid average emission factor as the default. See Section 3.3.1 for a description.

6. National Emission Factor

If residual mix factors or regional factors are not available, organizations can use a national grid average emission factor as the default. See Section 3.3.1 for a description.

3.3.3 Applying Emission Factors to Consumption

To accurately quantify emissions using the location-based and market-based methods, the selected emission factors must be multiplied by the appropriate quantity of electricity purchases. In cases where the electricity for an organization's facility is purchased entirely from a single source, the entire quantity purchased is multiplied by one location-based emission factor and one market-based emission factor. If electricity is purchased from multiple sources, then multiple factors may be required. For each distinct quantity that is purchased from a different source, the organization should select the appropriate emission factor for that purchase and that source. For example, a portion of the electricity for an organization's facility may be purchased through a direct line connection, and this quantity would be multiplied by the direct line emission factor. The remainder of the electricity may be purchased from a grid supplier, and this quantity would be multiplied by the appropriate factor from the hierarchy. Another example is a case where a portion of the electricity for an organization's facility is purchased through RECs or a PPA, and the rest from the grid.

Organizations may also need to determine at which of their facilities to apply emission factors. If a contractual instrument is purchased by a specific facility or is intended to apply to a specific facility, the emission factor associated with that instrument should be applied in the emissions calculation for that facility. One example of this is the purchase of green power for a facility's green building rating. Another example is a case where a specific facility has a PPA. The use of supplier-specific emission factors is another example because these factors should be applied based on the supplier serving a specific facility.

Another common means of purchasing contractual instruments is at an organization-wide level, with the instruments not applied to any specific facilities. An example of this is an organization-wide purchase of RECs. In this case, it is recommended that the contractual instruments be distributed evenly across all facilities proportional to their electricity consumption, so that each facility has the same percentage of their consumption met by the contractual instrument.

An organization should consider the alignment of its inventory reporting year and the timeframes of its purchasing agreements. If those timeframes align, the agreement and the associated emission factors can be applied for the entire reporting year. If they do not align, such as if the reporting year is based on a fiscal year and a purchasing agreement is for a calendar year, the emission factors for a purchasing agreement should only be applied to the portion of the reporting covered by that agreement. A given reporting year may be covered by two different purchasing agreements, or there may be portions of the reporting year which are not covered by any purchasing agreement.

3.3.4 Steam, Heat, and Cooling Emission Factors

Steam, heat (in the form of hot water), and cooling (in the form of chilled water) are typically purchased through a direct line connection with a generating facility. These energy sources are also commonly distributed through a district energy system, which is a grid system covering a limited geography supplying multiple end-users with energy produced by one or more energy generating facilities.

The organization should quantify and report emissions from steam, heat, and cooling purchases using both the location-based and market-based methods. As such, the location-based and market-based emission factor hierarchies in Section 3.3.1 and 3.3.2 also apply to steam, heat, and cooling. However, there are generally fewer emission factor options for purchased steam, heat, or cooling.

Direct line emission factors are applicable, as are regional grid factors that consider the extent of a district energy system. In both cases, appropriate emission factors should be obtained directly from the suppliers. If factors are not available, the organization can calculate emission factors based on the fuels used for generation and the efficiency of generation. An emission factor per unit energy for purchased steam or heat is equal to the emission factor per unit energy of the fuel used divided by the thermal efficiency of the generation. If necessary, default values of natural gas fuel and 80 percent thermal efficiency can be assumed. An emission factor for purchased cooling that is generated by an electric chiller is equal to the emission factor for the electricity consumed in the chiller divided by the chiller's coefficient of performance (COP). If energy is supplied from a CHP plant, refer to Section 2.2 for guidance.

Emission factors associated with energy attribute certificates or contracts may also apply to purchases of steam, heat, or cooling if an organization uses these contractual instruments and they meet the quality criteria in Section 4.

3.3.5 Updating Emission Factors over Time

All scope 2 emission factors represent the emissions profile for generation during a specific period of time. This emissions profile can change over time, due to changes in the resource mix and generation efficiency supplying the electricity. As a result, the emission factors may be updated periodically to reflect these changes. Organizations may also make different choices in their purchase decisions over time, such as beginning to buy RECs. These represent real changes in the emissions associated with an organization's electricity purchases. As such, it is recommended that organizations use the newest emission factors available at the time they calculate emissions for a reporting year.[5] Because these changes in emission factors do not represent a methodology change, prior years' emissions need not be adjusted to reflect new factors.

At times, there may be changes in the methodology used to develop emission factors. In addition, an organization may change the type of emission factors being used due to availability of factors. These are examples of a methodology change in the organization's GHG inventory, and in such cases, prior years' emissions should be adjusted in a manner consistent with the organization's base year adjustment policy.

3.3.6 Treatment of Biomass

For electricity generated through combustion of biomass (non-fossil) fuels (e.g., agricultural waste or biomass-derived gases), CH_4 and N_2O are to be included in the reported scope 2 emissions, and CO_2 is to be reported separately from the scopes. This applies to both location-based and market-based emissions. To accomplish this, electricity emission factors

[5] This applies whether an organization uses a calendar year period or other period for their GHG Inventory. For example, if an organization is calculating a GHG Inventory in August for a July through June reporting year, the inventory should use the newest factors available in August.

used for scope 2 calculations should include biomass CH_4 and N_2O emissions. Separate factors for biomass CO_2 are also needed. Grid average emission factors in eGRID include biomass CH_4 and N_2O emissions and do not include biomass CO_2 emissions, which is consistent with what should be reported in the scopes. eGRID does not currently report biomass CO_2 emission factors, but it contains plant-level biomass CO_2 emissions information that could be used to quantify biomass CO_2 emissions from electricity purchases. In addition, there are specific biomass fuel combustion emission factors available from the EPA Greenhouse Gas Reporting Program. These are provided in Table 1 of EPA's GHG Emission Factors Hub.

In cases where waste materials are combusted for energy rather than landfilled, the biogenic portion of combusted waste materials should be considered as biomass and accounted for accordingly.

There has been increased scientific inquiry into GHG accounting for biomass in energy production. The EPA's Science Advisory Board found that "there are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality may not an appropriate assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably." [6] According to the GHG Protocol, "consensus methods have yet to be developed under the GHG Protocol Corporate Standard for accounting of sequestered atmospheric carbon as it moves through the value chain of biomass-based industries," though some general considerations for accounting for sequestered atmospheric carbon are discussed in Chapter 9 and Appendix B of the GHG Protocol.

3.3.7 Sale of Certificates from On-site or Direct Line Generation

An on-site energy generation facility owned by the organization may generate energy attribute certificates that are eligible for sale in voluntary or compliance markets. If the organization sells the certificates, they transfer to the buyer the energy attributes associated with the generation, including the type of energy and its emission factor. In this situation, the organization should add the emissions associated with the sold certificates to its scope 2 emissions. The organization would multiply the quantity of generation represented by the sold certificates by grid average emission factors for the location-based method and by residual mix emission factors for the market-based method if available, or by grid average emission factors.

Alternatively, an organization may have a direct line connection with a generation facility that generates certificates. This could be a generation facility located off-site, or an on-site generation facility that is owned or operated by another organization. If the organization has not acquired the certificates from the direct line generation facility, emissions from the electricity purchased from the facility must be quantified using grid average emission factors for the location-based method and residual mix emission factors for the market-based method if available, or by grid average emission factors. A common example of this is a case where an on-site renewable energy system is owned by an external party. The electricity may be sold to the reporting organization, but the RECs may be sold to another party.

[6] EPA Science Advisory Board Review of the 2011 Draft Accounting Framework for CO_2 Emissions for Biogenic Sources Study. 2012. https://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument.

Section 4: Quality Criteria

The following are scope 2 quality criteria defined by the GHG Protocol Scope 2 Guidance. All contractual instruments used in the market-based method for scope 2 accounting shall:

1. Convey the direct GHG emission rate attribute associated with the unit of electricity produced. This can be achieved in the following situations: a certificate conveys all energy attributes; multiple certificates are generated for the same MWh of generation, and only one (or a pairing of multiple instruments) conveys claims about the energy type and GHG emission rate; or certificates do not specify attributes, but no other consumer is claiming emission rate attributes.
2. Be the only instruments that carry the GHG emission rate attribute claim associated with that quantity of electricity generation.
3. Be tracked and redeemed, retired, or canceled by or on behalf of the reporting entity. This can be done through a tracking system, an audit of contracts, third-party certification, or other means.
4. Have a vintage that matches as closely as possible to the date of the reporting period to which the instruments are applied. The vintage of the instrument is based on the date of the energy generation that the instrument represents. EPA's recommended best practice is for instruments to be applied to a reporting period if the associated energy generation occurred within the reporting period, up to six months prior to the reporting period, or up to three months after the reporting period.
5. Be sourced from the same market in which the reporting entity's electricity-consuming operations are located and to which the instrument is applied. A market is defined as a geographical area which operates under a common regulatory authority and has a common system for trading and retiring contractual instruments. The policy on market boundary definitions is not universally in concurrence, however, and can vary in interpretation across different programs and guidance. This document represents EPA's recommendation that the U.S. be considered a single market based on its common regulatory landscape, despite the U.S. having sub-national grids and some physical connectivity with adjacent countries.[7]

The following are EPA best-practice recommendations that go beyond the minimum requirements in the GHG Protocol Scope 2 Guidance.

EPA recommends that organizations procure instruments that are surplus to supply quotas, such as state renewable portfolio standards (RPS), mandates placed on utilities or load-serving entities, or consent decrees. An example would be purchasing a voluntary REC that is properly retired and cannot be used to meet an RPS. The following are examples where regulatory surplus is <u>not</u> achieved for the electricity generation associated with the instrument. This would most typically apply to renewable generation, but could also apply to generation with other technologies.

1. Electricity generation is used to satisfy RPS mandates or goals imposed by federal, state or local governments on utilities or load serving entities.

[7] The reciprocal acknowledgment of contractual instruments across country borders and regulatory authorities should be a requirement to define a market encompassing more than one country. To be viewed as a single market, adjacent countries should have a binding agreement for reciprocal recognition of contractual instruments across country borders, which does not currently exist between North American countries (U.S., Canada, and Mexico). In contrast, the European Union countries have established a legal and regulatory system for reciprocal acknowledgement of contractual-based instruments across member country borders. Thus, the EU is considered a single market.

2. Electricity generation is included in an undifferentiated power product (e.g., standard electricity service or utility system mix).
3. Electricity generation is being paid for by all customers (e.g., in a utility's standard rates).
4. Electricity generation comes from an eligible renewable generator that has been mandated by a local, state or federal government agency (e.g., in a consent decree).
5. Electricity generation is purchased instead of paying a system benefits charge for renewable electricity (e.g., a self-directed system benefits charge).
6. Electricity generation is purchased as part of a Supplemental Environmental Project (SEP) under a Clean Air Act enforcement action.
7. Electricity generation is sourced from a state that has a mandatory GHG cap in place for power plant emissions or similar regulatory mechanism, unless emission allowances are retired on behalf of the energy buyer, such as in the Regional Greenhouse Gas Initiative (RGGI). For purchases from those states to be eligible, organizations should communicate with their provider about whether the necessary administrative steps are being taken to secure this result.

The following are circumstances in which EPA has recognized a purchase of electricity generation as surplus to other mandatory requirements:

1. The purchase is a result of an obligation placed on federal, state, or local government agencies as end-users of energy via a state or federal executive order.
2. The purchase is included as a voluntary measure in a State Implementation Plan (SIP) under the federal NO_x Budget Trading Program. Although SIPs are mandated, they do not set mandatory requirements for the use or purchase of renewable energy. Therefore, a purchase of green power under a SIP is considered a voluntary purchase.

For organizations purchasing green power products, EPA's Green Power Partnership (GPP) identifies additional best-practice quality criteria that organizations may consider. For example, eligible sources of green power are identified (generating facilities 15 years old or newer that utilize wind, solar, geothermal, eligible biomass, or low-impact hydropower resources). In addition, EPA strongly encourages organizations to buy green power products that are certified by an independent third-party as a matter of best practice. Buying a certified green power product offers a higher certainty to customers that they are receiving the desired environmental benefits.

Section 5: Completeness

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

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

At the operational level, an organization should include all GHG emissions from the sources included in their inventory. Possible GHG emission sources are stationary fuel combustion, combustion of fuels in mobile sources, purchases of electricity, emissions from air conditioning equipment and process or fugitive emissions. Organizations may refer to this guidance document for calculating indirect emissions from electricity purchases and to the Center's GHG Guidance documents for calculating emissions from other sources. The completeness of facility level data can be checked by comparing the facility energy bills against accounting records of expenditures for electricity.

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

Section 6: Uncertainty Assessment

There is some level of uncertainty associated with all methods of calculating GHG emissions. It is recommended that organizations attempt to identify the areas of highest uncertainty in their emissions calculations and consider options for improving the quality of this data in the future.

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

The accuracy of calculating emissions from purchased electricity is also determined by the emission factors used to convert purchases into indirect emissions. Average grid emission factors are not completely accurate because the factors vary by time of day and season based on what units are operating (e.g., base load vs. peaking load). Factors may be even more uncertain if the data are calculated for a year that differs from the year of purchase. If using emission factors from eGRID, keep in mind that data may be out of date.

Section 7: Documentation

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

Table 1: Documentation Sources for Purchased Electricity

Data	Documentation Source
Amount of electricity purchased	Purchase receipts or utility bills, contract purchase or firm purchase records
Quantity of energy attribute certificates purchased	Purchase receipts, contracts
Location-based and market-based emission factors used	Records from contracts, suppliers, or published sources
Prices used to convert cost of electricity to amount of electricity consumed	Purchase receipts or utility bills contract purchase or firm purchase records; EIA, EPA, or industry reports
Any assumptions made	All applicable sources

Section 8: Inventory Quality Assurance and Quality Control (QA/QC)

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

- Electricity bills can also be compared to actual meter readings to verify they are accurate representations and not estimates.
- Data on electricity use can be compared with data provided to the Department of Energy or other EPA reports or surveys.
- If sub-meter data on electricity use is the basis for determining electricity use, then care should be taken to ensure that the sum of the sub-meters represents the full electricity consumption of the organization's facility.