California Climate Action Registry General Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions

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Abbreviations and Acronyms

AFV	Alternative Fuel Vehicle
Btu	British thermal unit(s)
CARB	California Air Resources Board
CARROT	Climate Action Registry Reporting Online Tool
CBECS	Commercial Building Energy Consumption Survey
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CFC	chlorofluorocarbon
CHP	combined heat and power
CH_4	methane
COI	conflict of interest
COP	coefficient of performance
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
eGRID	Emissions & Generation Resource Integrated Database
EIA	U.S. Energy Information Administration
EIIP	Emissions Inventory Improvement Program
EPA	U.S. Environmental Protection Agency
g	gram(s)
GCV	gross caloric value
GHG	greenhouse gas
GRP	General Reporting Protocol
GWP	global warming potential
ha	hectare(s)
HCFC	hydrochlorofluorocarbon
HDV	heavy duty vehicle
HFC	hydrofluorocarbon
HHV	higher heating value
HSE	health, safety, and environmental
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
ISO	International Organization for Standardization
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound
LDT	light duty truck
LHV	lower heating value
LPG	liquefied petroleum gas
Mcf	thousand cubic feet
mi	mile(s)
MMBtu	one million British thermal units
MWh	megawatt-hour(s)
NCV	net caloric value
NO_x	oxides of nitrogen
N_2O	nitrous oxide
ODS	ozone depleting substance
PFC	perfluorocarbon
RFA	Request for Applications
SAR	IPCC Second Assessment Report (1996)
SF_6	sulfur hexafluoride
TAR	IPCC Third Assessment Report (2001)
T&D	transmission and distribution
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Part I Introduction

The General Reporting Protocol (the GRP) provides guidance for businesses, government agencies, and non-profit organizations to participate in the California Climate Action Registry (the California Registry), a voluntary greenhouse gas (GHG) registry.

The GRP provides the principles, approach, methodology, and procedures required for participation in the California Registry. It is designed to support the complete, transparent, and accurate reporting of an organization's GHG emissions inventory in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, electricity use, and GHG emissions in a quantifiable manner. The GRP guides participants through the reporting rules, emission calculation methodologies, and the California Registry's standardized reporting mechanism via its web-based reporting system, the Climate Action Registry Reporting Online Tool (CARROT). Reporting guidance for individual industries in the form of sector-specific protocols have been developed over time, and supplement this document. The current version of the GRP and its appendices are available for download on the California Registry's website, www.climateregistry.org.

In addition to the GRP, the California Registry currently offers four sector-specific protocols:

- Cement Protocols,
- Forest Protocols,
- Local Government Operations Protocol, and
- Power/Utility Protocols.

Additional protocols have been developed over time. The sector-specific protocols are considered appendices to the GRP. Forest companies, power generators and electric utilities, cement companies, and local governments should refer to the GRP as well as their respective sector-specific protocol for a complete set of emission accounting and reporting instructions.

By joining the California Registry, participants agree to report their annual GHG emissions according to the guidelines in this Protocol and its appendices. The GRP is intended to be used in combination with the California Registry's General Verification Protocol (GVP) and web-based calculation and reporting tools.

I.1 How to Use the General Reporting Protocol

Who Should Use the GRP

- Businesses, government agencies, and non-profit organizations who want to learn about greenhouse gas emissions tracking for California or nationwide
- California Registry members who are reporting their general emissions or emissions related to a specific sector (forests or utilities)
- Verifiers of general or sector-specific emissions reports
- Technical advisors to companies who report emissions through the California Registry
- The interested general public

How the Protocol is Organized

This Protocol is based on the "Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard" developed by the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI) through "a multi-stakeholder effort to develop a standardized approach to the voluntary reporting of GHG emissions."[1] The calculations and emission factors were selected based on technical advice provided to the California Registry by the State of California.

This Protocol will continue to be refined over time, to add clarity and specificity, to provide guidance for specific industries, and to incorporate new understanding in GHG accounting. Comments on the GRP or other protocols may be submitted to the California Registry using the Protocol Comment Form posted on the California Registry's website.

The Protocol is divided into four parts, composed of a total of fourteen chapters. Each chapter provides guidance on the specific steps participants will need to take to complete and submit their GHG emissions report to the California Registry. Depending upon the complexity and the nature of reported GHG emissions, some of the steps in this Protocol may not apply to all organizations. Nevertheless, the California Registry encourages participants to review the document as a whole to ensure that they have identified all reporting requirements.

1 "The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard," World Business Council for Sustainable Development and World Resources Institute, Switzerland, March 2004 (GHG Protocol, 2004).

Part I Introduction

Contains:

- An overview of the GRP and the reporting process
- An introduction to online reporting
- A brief background on the creation and objectives of the California Registry
- Answers to key questions about using the GRP

Part II Determining What You Should Report (Chapters 1-4)

Provides guidance on:

- Determining geographic boundaries (i.e., California, the entire U.S., or worldwide)
- Determining organizational boundaries
- Determining operational boundaries
- Setting an emission baseline

Part III Quantifying Your Emissions (Chapters 5-12)

Provides guidance on calculating:

- Indirect emissions from electricity
- Direct emissions from mobile combustion
- Direct emissions from stationary combustion
- Indirect emissions from co-generation, imported steam, and district heating or cooling
- Direct process emissions
- Direct fugitive emissions
- Optional emissions

Part IV Completing and Submitting Your Report (Chapters 13-14)

Describes how to finalize emissions reports by:

- Determining de minimis emissions
- Preparing and submitting an annual GHG emissions report using CARROT
- Providing an overview of the verification process

Related California Registry Documents

General Verification Protocol: for approved verifiers, California Registry members, and the public interested in verification.

Forest Protocols: for landowners with at least 100 acres of forestland in California. The Forest Protocols consist of three documents: 1) an entity-level protocol, 2) a project protocol, and 3) a verification protocol. Like the GRP and the General Verification Protocol, the forest sector entity-level and verification protocols provide GHG emissions accounting, reporting, and verification guidance at the entity-level. The forest project protocol provides guidance to forest companies that wish to account and report GHG emission reductions resulting from one of three planned activities taking place on the forest company's land: conservation, reforestation or conservation-based forest management.

Power/Utility Protocols: for companies that generate and sell electricity for the wholesale or retail market and/or provide electricity transmission and distribution services. The Power/Utility Protocols consist of two documents: 1) an entity-level protocol and 2) a verification protocol.

Cement Protocols: for companies that manufacture cement. The Cement Protocols consist of two documents: 1) the entity-level protocol and 2) a verification protocol.

Local Government Operations Protocol: for local governments to quantify and report GHG emissions inventories of their municipal operations. The Local Government Operations Protocol consists of one document: 1) the entity-level protocol.

I.2 Background on the California Climate Action Registry

The California Registry is a private non-profit organization that serves as a voluntary greenhouse gas registry to protect, encourage, and promote early actions to reduce GHG emissions. The California Registry provides leadership on climate change by promulgating credible and consistent GHG reporting standards and tools for organizations to measure, report, verify, and reduce their GHG emissions in California and/or the U.S. Following considerable initiative and input from various stakeholders from the business, government, and environmental communities, the California State Legislature established the California Registry in 2000, with technical modifications in 2001.[2]

The purposes of the California Registry are as follows:

1. To enable participating entities to voluntarily measure and record GHG emissions produced after 1990 in an accurate manner and consistent format that is independently verified;
2. To establish standards that facilitate the accurate, consistent, and transparent measurement and monitoring of GHG emissions;
3. To help various entities establish emissions baselines against which any future federal GHG emissions reduction requirements may be applied;

2 California Senate Bill 1771 was signed into law on September 30, 2000, and Senate Bill 527 on October 13, 2001.

4. To encourage voluntary actions to increase energy efficiency and reduce GHG emissions;
5. To ensure that participating organizations receive appropriate consideration for verified emissions results under any future state, federal or international regulatory regime relating to GHG emissions;
6. To recognize, publicize, and promote participants in the California Registry; and
7. To recruit broad participation in the process.

The California Registry was created by the State of California to be a non-profit organization operating outside of the state government, but working closely with the State to develop its reporting and verification procedures such that the State is confident in the quality of the data. To this end, the State has worked closely with the California Registry since its inception to develop its reporting and verification guidance, including both this General Reporting Protocol, the companion Verification Protocol, and also industry-specific reporting protocols.

Joining the California Registry provides several benefits, such as:

1. **Addressing inefficiency –** understanding that emissions are an indication of waste and inefficiency has led many companies to redesign business operations and processes, spur innovation, improve products and services, and help to build competitive advantage.
2. **Managing risk –** taking steps to protect early actions ahead of possible future GHG regulations is a wise risk-management strategy.
3. **Preparing for trading –** developing credible and transparent measurement, verification and reporting methods in order to participate in any future emission trading system.
4. **Showing environmental leadership –** acting early to address climate change to better influence future policy, and to understand the most cost-effective means of managing and reducing emissions.
5. **Demonstrating action on GHG emissions –** reporting verified information to the California Registry helps to address shareholder concerns about adequate corporate actions to reduce GHG emissions.
6. **Preparing for regulation –** verifying an annual GHG inventory helps to prepare for mandatory GHG reporting.

I.3 GHG Accounting and Reporting Principles

The following principles, which serve as the basis of reporting and verifying emissions with the California Registry, are consistent with the WRI/WBCSD GHG Protocol Initiative.[3]

Relevance. Relevant GHG inventories submitted to the California Registry appropriately reflect the GHG emissions of the entity and include emissions information produced in accordance with the program rules on defining reporting boundaries and sources.

Completeness. Complete GHG inventories include emissions from all GHG sources and activities within the specified scope of the participant's report. Baseline and annual emissions results include all sources; vertical and horizontal integration should be properly accounted for.

Consistency. Consistently developed GHG inventories enable meaningful comparison of emissions performance over time and across similar organizations. Additionally, changes to a participant's emission baselines are verified to ensure appropriate comparisons.

Accuracy. Accurate GHG inventories must be within the materiality threshold of 5% of the verifier's estimate of total emissions. The verification process validates the accounting and reporting decisions made by the participant and ensures that the GHG emissions reports are precise and credible.

Transparency. Reporters must make available to their verifiers the necessary information and documentation used to produce the inventory. Additionally, the verification process should be clearly and thoroughly documented to allow the possibility for outside reviews by the State or the California Registry.

I.4 Reporting Requirements and Disclosure

Required Reporting

California Registry participants must submit their GHG emissions to the California Registry each year. Any entity that conducts business activities in the State of California—such as a corporation or other legally constituted body, a non-profit organization, any city, county, or State government agency—may join the California Registry. If an organization does not have emissions in California, then it may report its total U.S. emissions and indicate that California emissions are zero. At a minimum, participants must report their entity-wide emissions for each of the following categories:

- Direct emissions from mobile source combustion
- Direct emissions from stationary combustion

3 GHG Protocol, 2004.

- Indirect emissions from electricity use, imported steam and district heating and cooling
- Direct process emissions
- Direct fugitive emissions

For the first three years after joining the California Registry participants must report at a minimum their CO_2 emissions in California or in the U.S., depending on the geographic scope of their inventory. Starting with the fourth year, participants must report all Kyoto GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6). Participants must submit annual GHG emissions reports (emissions reports) via CARROT. Each annual GHG emissions report must contain at least the following information:

- The geographic scope of the emissions report (whether California-only or nationwide);
- The operational and organizational boundaries of the reporting entity for which GHG emission data is reported;
- A GHG emissions baseline to assess changes in total emissions from year to year, if a participant chooses to define a baseline;
- Total significant direct GHG emissions (including mobile and stationary combustion, process, and fugitive);
- Total significant indirect GHG emissions (from electricity usage, and from co-generation, steam imports, district heating and cooling); and
- Total direct and indirect emissions classified as de minimis.

Before emissions reports will be accepted by the California Registry, this information must be verified by an approved verifier. Participants are eligible to report and receive verification through the California Registry for both California-only and national GHG emission inventories. Verifiers are screened and approved by the California Registry to ensure that they have the necessary skills to appropriately evaluate emissions reports.

The purpose of the verification process is to ensure that the emissions report meets the following criteria:

- Relevance: Report GHG emissions in accordance with the program rules on defining reporting boundaries and sources, using the methodologies and emission factors outlined in the General Reporting Protocol.
- Completeness: Report all significant emissions, defined as at least 95% of the total (both direct and indirect emissions), entity-wide sources (either California-only or nationwide) and disclose any de minimis emissions.
- Consistency: Report total emissions each year of participation in the California Registry.
- Transparency: Report emissions to the California Registry using the California Registry's standardized reporting tool, the Climate Action Registry Reporting Online Tool (CARROT).
- Accuracy: Less than a 5% difference between your calculated total emissions and what an approved verifier calculates your emissions to be.

For every year that a participant has a current annual emissions report, they are considered a *Climate Action Leader*.

Optional Reporting

Each annual GHG emissions report may also contain optional information provided by the participant to highlight their organization's environmental goals, policies, programs and performance, and to report other GHG emissions information. This information is not required to be reported and thus is not verified, but is valuable in providing transparency and enhancing public knowledge. All emissions reports will clearly distinguish between information that is and is not verified. Once accepted by the California Registry, optional information is made available to the public as part of the emissions report.

Participants disclose to the public only information contained in the emissions reports generated through CARROT that include entity-wide emissions from direct and indirect sources, as well as any optional data they consider relevant. Although the California Registry will make available aggregated entity-level emissions data to the public, it will keep all other data (i.e., from the facility- or source-level) confidential, such as activity data, methodologies, and emissions factors. Only the participant, the participant's verifier, and the California Registry can access confidential information, unless the participant allows others to access such information.

I.5 Reporting Uncertainty vs. Inherent Uncertainty

Reporting uncertainty entails the mistakes made in identifying emissions sources, managing data or information, and calculating GHG emissions. Inherent uncertainty refers to scientific uncertainty associated with measuring GHG emissions. The California Registry is aware that there is inherent uncertainty in emissions factors and measurement of activity data through metering and instrumentation – even after the calibration of meters and other data collection methods are verified as accurate.

The GHG emissions accounting and reporting guidelines in the GRP and the independent verification process developed by the California Registry are designed to reduce reporting uncertainty such that it is less than the minimum quality standard. Determining scientific

accuracy is not the focus of the California Registry or its General Reporting Protocol.

I.6 Web-Based Reporting

CARROT (Climate Action Registry Reporting Online Tool)

Submitting an annual GHG emissions report to the California Registry is designed to be as simple and straightforward as possible. Based on this Protocol, the California Registry has developed a web-based reporting application called CARROT (Climate Action Registry Reporting Online Tool), which enables participants to submit emissions reports online.

CARROT serves two purposes: (1) it is the tool through which participants report their emissions, and (2) for many categories of data, it can assist with emissions calculations. It is accessed through the California Registry's website. All emissions information must be reported through CARROT. The website also provides a variety of technical resources for getting started, context-based Help links, and other supporting information including an electronic version of the GRP.

A short demonstration of CARROT and the *CARROT Getting Started Guide Version 3* can also be found on the California Registry's website.

I.7 Technical Assistance

The California Registry has a number of ways to help you as you proceed through the emissions reporting process. You can contact California Registry staff if you have questions or problems at:

- help@climateregistry.org
- 213-891-1444 ext.2 and ask for the Programs Team

Also, CARROT has online help that may answer many of your questions.

Should you need additional assistance, you can also hire a firm to provide technical assistance. A list of State- and California Registry-approved technical assistance providers is on the California Registry's website as a reference.

I.8 CARROT Training and Reporting Orientation

The California Registry holds regular Reporting Orientation sessions to help participants understand how to use the General Reporting Protocol and CARROT application. These workshops include specific guidance on calculating and verifying GHG emissions. All interested parties are invited to participate.

Please contact the California Registry (213-891-1444) for more details and see the website for a calendar of upcoming events (www.climateregistry.org).

I.9 Key Questions

Below are clarifications on some basic issues that should assist you as you begin to prepare your annual GHG emissions report. If you have a question that is not answered in this Protocol, please contact the California Registry.

Membership: How do I join the California Registry?

As of October 31, 2008, the California Registry directs all organizations interested in reporting entity-level emissions to our sister organization, The Climate Registry (www.theclimateregistry.org).

The California Registry accepts emissions inventory information from current members through October 31, 2010. In the meantime and going forward, interested parties may become Affiliates of the Climate Action Institute (Institute). Building on the California Registry's community of leaders in business, government, and civil society, the Institute provides education and a forum for discussion on emerging climate policy issues in the West. The Institute continues many of the historic California Registry member services such as climate policy conference call briefings, trainings, an annual conference, Climate Action Champion awards, publications, an annual delegation to the UN Climate Change Conference, and much more.

For information on becoming an Affiliate of the Climate Action Institute, please contact help@climateregistry.org or 213-891-1444, extension 2.

Member Benefits: What are some of the advantages of joining the California Registry?

Being a member of the California Registry provides several important benefits to participants, such as addressing inefficiency, managing risk, preparing for emissions trading, showing environmental leadership, demonstrating action on GHG emissions, and preparing for possible CO_2 regulation.

Emissions Trading: Can I use my California Registry GHG emissions report to trade GHG emissions?

The General Reporting Protocol provides guidance for calculating an organization's entity-wide GHG emissions inventory, not for creating tradable GHG credits. The

California Registry itself does not serve as a brokerage house for GHG emissions trading, but the reporting and verification processes adopted by California Registry participants will promote credibility, transparency, and accuracy of the data reported. It is possible that information reported to the California Registry can be used by the participant to facilitate participation in private or government-sponsored trading programs in the future, although it is likely that any emissions to be traded will be documented and verified from emissions reduction projects. The California Registry is in the process of developing a wider range of emissions reduction project-based reporting and verification protocols.

Eligibility to Report: **Who may report their GHG emissions?**

Any organization can participate in the California Registry if it can report either its total California emissions, or its total U.S. emissions. If an organization does not have emissions in California, then it may report its total U.S. emissions, and indicate that its California emissions are zero. Organizations with operations in multiple states may not register a single state's emissions (except California emissions). Partial nation-wide reporting is not permitted.

Adhering to the Protocol Guidelines: **Must a company or organization follow this Protocol to participate in the California Registry?**

Participants in the California Registry are expected to make every effort to report in a manner consistent with this Protocol. However, the California Registry recognizes that participants may face unique situations not addressed in the Protocol or in some cases the implementation of the Protocol would create undue burden. While the California Registry seeks to maintain consistency in reporting, participants may use calculation methodologies and emission factors that are verified as more accurate than the default calculations. The California Registry also welcomes suggested revisions to the Protocol.

All comments about the Protocol should be submitted to the California Registry using the Protocol Comment Form, available on the website (www.climateregistry.org). Suggestions should clearly document an alternative approach and the manner in which the alternative approach would continue to improve the Protocol. Suggested revisions will be reviewed by California Registry staff and advisors, then summarized and presented to the California Registry Board for review annually. Changes to the Protocol will be approved by the Board and publicly announced.

Level of Reporting: **Are participants permitted to report only individual facilities?**

At a minimum, you are required to report emissions from all sources in the state of California. If you have multiple facilities, you must report emissions from all facilities. The California Registry encourages members to report at a sub-entity- or facility-level as part of your entity-wide GHG emissions report in CARROT.

A sub-entity may be a business unit, a department or other grouping that you define. If reporting at the sub-entity level, you must report all of your organization's facilities or operations, such that all sub-entity emissions equal your entity's total California or U.S. emissions.

Required Emissions Reporting: **Which GHGs do participants report?**

The California Registry accepts GHG emissions reports that include emissions of the following six GHGs (Kyoto gases):

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur Hexafluoride (SF_6)

Although participants are encouraged to report all of these gases starting in year one, participants 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 will be required to include emissions from all six of the Kyoto GHGs (if applicable) in the annual emissions report.

For example, if you joined the California Registry in January 2006, you would report at least your CO_2 emissions emitted during the calendar years 2006-2008. Beginning in calendar year 2009, you must report all six Kyoto gases for this and every subsequent year.

You should report all required direct and indirect emissions. Direct emissions are those emitted from sources owned or controlled by the reporting entity. For example, a cement manufacturer would report direct emissions resulting from the process of manufacturing cement. Indirect emissions are those that result from a participant's actions but are produced from sources owned or controlled by another entity. For example, a participant whose emissions result only from the consumption of electricity would calculate its indirect emissions from the amount of electricity it consumes.

What are de minimis emissions? Do I have to calculate and report absolutely everything?

To be verified, your emissions report must identify all of the sources in your inventory, no matter how small. However, to help reduce reporting burdens and concentrate efforts on your significant emissions, the California Registry permits you to designate a small portion of your emissions as de minimis. De minimis emissions comprise less than 5% of your organization's total GHG emissions, as produced from any combination of sources and gases.

For some participants, identifying and quantifying all of their GHG emissions according to the methodologies in the GRP would be unduly burdensome and not cost-effective. A participant may operate hundreds, if not thousands, of small facilities where the known emissions—including, for example, indirect emissions from electricity consumption or direct emissions from motor vehicle operation—are a small fraction of larger emissions sources from industrial activities. If you can provide estimates that these emissions total less than 5% of your total annual GHG emissions, you do not have to calculate them according to the methodologies in the GRP. De minimis emissions still need to be included in your emissions report.

For example, a participant estimates that it emits 1,000 metric tons of CO_2 each year. Most of these emissions come from an on-site heating and cooling system in its buildings. In addition, this participant also has one company car that is driven approximately 20,000 miles each year. This participant estimates that between 800 and 1000 gallons of gasoline are consumed by this car each year. Using the upper estimate of 1000 gallons, the participant calculates the emissions from this source as 8.8 tons of CO_2/year, and finds that this amount falls below the de minimis threshold of 5% or 50 metric tons CO_2/year. The participant can report this emission source as de minimis in CARROT and provide this estimation to the verifier, along with vehicle records showing the actual miles traveled of the car. In subsequent years, if the operation patterns do not change significantly, the participant can continue to declare and report the emissions from this source as de minimis, and will only need to re-estimate this information every three years.

Historic Data: Can I report emissions data for years prior to the year I joined the California Registry?

Some participants may wish to report GHG emissions data for years prior to the year in which they joined the California Registry. When you join the California Registry, you must specify for which calendar year of emissions you will first report to the California Registry and report your emissions according to the version of the General Reporting Protocol in force at the time of joining. Emissions reported for years prior to the actual year a participant joins the California Registry are considered "historical data" and the participant should use the GRP in force at the time of joining for reporting these data. For each year of historical data, you must report at least your emissions of CO_2. You may also report entity-wide emissions of individual gases for which you have verifiable data, and for which you can report it from that point forward. All historical data must be verified before it can be accepted into the California Registry.

For every year that you report to the California Registry, you must report the emissions associated with all of your operations within your geographic boundary (either California or U.S.). When you choose to report historical data, you must also report all of the emissions associated with all of the facilities you owned or operated in each calendar year. By providing this information, you provide an accounting of your organization's emissions over time. When you re-adjust your emissions baseline to reflect structural changes, you demonstrate your emissions performance over time. The California Registry supports consistent and transparent reporting and verification of annual GHG emissions. In this regard, emissions reports for years prior to joining the California Registry need to comply with the same requirements as for current annual GHG emissions inventories.

Reporting and Reporting Deadlines: How do I report? When do I report?

All participants must report at least their California-wide emissions of carbon dioxide (years 1-3) and all Kyoto gases (years 4+) in five reporting categories to the California Registry using CARROT, the online reporting tool. You can also choose to input your source- and facility-level emissions information using CARROT. CARROT can also help you calculate your emissions in many common emission categories.

You should work to report your emissions in CARROT by no later than June 30 of the year after they were produced, and complete verification by October 31 of the same year. For instance, you should report your 2008 emissions by June 30, 2009 and complete verification by October 31, 2009.

There cannot be any gap years in the data you report. For example, if you joined the California Registry in January 2006, you would report at least your CO_2 emissions for 2006 by June 30, 2007. You would follow the same timetable for reporting your 2007 and 2008 emissions. Beginning with your 2009 emissions, you must report all 6 GHGs by June 30, 2010.


Table I.1 illustrates the minimum reporting requirements over time for a new participant.

Table I.1 Reporting Years

Year	Participant Action
2006	Participant joins the California Registry and tracks 2006 emissions
2007	Participant tracks 2007/reports 2006 CO_2 emissions
2008	Participant tracks 2008/reports 2007 CO_2 emissions
2009	Participant tracks 2009 emissions for all six GHGs/reports 2008 CO_2 emissions
2010	Participant tracks 2010 /reports 2009 emissions for all six GHGs

Confidentiality: **Will the information I report be kept confidential?**

As described above, the public can only view aggregated entity-level emissions data reported to the California Registry. Confidential information will only be accessible to you, the California Registry, and your chosen verifier, unless you allow others to access such information or wish to have it available to the public.

Verification: **Must my report be verified?**

Yes. However, the California Registry understands that in the initial years of participation, some reports may not be verifiable due to the need to change data collection practices or other factors that make it impossible to meet the reporting requirements. Thus, while you must calculate and verify your emissions for each year you wish to report, you are not required to submit your Verification Opinion to the California Registry for the first two years of your participation. This flexibility is intended to allow you to have time to fully understand the calculating, reporting, and verification processes before your emissions information is made available to the public. Participants are eligible to receive verification for California-only or U.S emissions reports. At this time, international emissions reports do not qualify for verification through the California Registry, although you can store international data in CARROT.

Minimum Quality Standard: **What are the requirements for verifying my emissions report?**

Any emissions report submitted to the California Registry must be free of material discrepancies in order to be verified. It is possible that during the verification process, differences will arise between the emissions estimated by the California Registry participant and those estimated by the verifier. These differences between participant and verifier estimations may be classified as either material or immaterial discrepancies. A discrepancy is considered to be material if the overall reported emissions differ from the overall emissions estimated by the verifier by 5% or more. Otherwise the difference is considered to be immaterial.

California Registry-Approved Verifiers: **Who must verify a GHG emissions report?**

In order to have your emissions report accepted into the California Registry database, it must be verified by an independent third-party organization that has been approved by the California Registry. A list of approved verifiers is provided to all California Registry participants and is available on the California Registry's website. The verification process is outlined in Chapter 14.

Before your preferred verifier is approved, the California Registry will review any pre-existing relationship between you and the verifier you select to determine if there is potential for conflict of interest. Also, a State of California representative may accompany a verifier on site visits, as part of their oversight of the verification process. If, in the course of these activities the state representative needs to view confidential information, the state representative will sign a confidentiality agreement with both you and your verifier to protect any information you designate as sensitive.

California Registry-Approved Technical Assistance Providers: **What role do they play?**

Some participants may desire expert assistance to collect, document, and report their emissions to the California Registry and/or otherwise manage and reduce their GHG emissions. The State and the California Registry approve firms qualified to serve as technical assistance providers (TAs). Approved companies have been screened as firms experienced in providing GHG emissions services, and many of them have attended California Registry-sponsored training sessions. Participants are not required to use approved TAs. Neither the California Registry nor the State is responsible for any consulting services or recommendations they may provide.

All firms approved as verifiers also are automatically qualified to act as TAs. A firm cannot provide both technical assistance and verification services to the same client at the same time. A list of technical assistance providers is available on the California Registry's website (www.climateregistry.org).

Role of California State Agencies: What is the relationship between the California Registry and State agencies?

The California Registry was established by California statute as a non-profit voluntary registry for greenhouse gas emissions inventories in order to help organizations to establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied. The State of California was directed to offer its best efforts to ensure that participants receive appropriate consideration for early actions in the event of any future state, federal or international GHG regulatory scheme.

The California Registry and state agencies work together and keep each other informed about current activities. The State of California continues to provide technical guidance to the California Registry and plays a direct oversight role in the verification process. The California Registry gives great weight to state agency guidance, and relies in large part on these recommendations when developing California Registry policies, procedures and tools, including reporting and verification protocols and the online reporting tool. However, final policy and technical decisions are made independently by the California Registry's staff and Board of Directors.

Part II Determining What You Should Report

As you begin to prepare your annual GHG emissions report to the California Registry, you first need to consider the geographic and organizational boundaries of your organization. That is, you need to determine which sources of emissions to include in your report based on their location, your organizational structure, and operations. For many participants, particularly firms that are wholly-owned entities operating entirely within the State of California, establishing reporting boundaries will be straightforward. For participants whose operations consist of jointly-owned entities and those with operations outside of California, the process may be more involved.

Part II is designed to help your organization assess what emissions and activities you should include in your report. Chapter 1 begins at the broadest possible level—your report's geographic boundaries. It discusses options for reporting your organization's emissions within the borders of the United States or for those only within the State of California—the minimum requirement for reporting to the California Registry.

After addressing geographic boundaries, Chapter 2 focuses more narrowly on organizational boundaries. The basic unit of participation in the California Registry is an entity in its entirety, as it relates to the geographic boundaries specified in Chapter 1. While only entity-level reporting is required, the California Registry strongly encourages organizations to report at the facility- or sub-entity-level; this greater level of detail builds a more credible database of information and facilitates verification. Organizations that wholly own and fully control all of their GHG emission sources will simply report all of their emissions to the California Registry. For facilities that are owned or controlled by more than one organization, determining organizational boundaries may be more complicated.

Once you have determined your geographic and organizational boundaries, Chapter 3 will help you consider the operational boundaries of your emissions, based on whether they are directly or indirectly caused by your organization.

Chapter 4 provides guidance on selecting a baseline year and on adjusting your baseline over time to capture any changes in the size and scope of your organization. After you have categorized your emissions and defined operational boundaries, you will be ready to move onto estimation methods in Chapters 5-11.

Chapter 1 Geographic Boundaries

> **Who should read Chapter 1:**
>
> Chapter 1 applies to all participants.
>
> **What you will find in Chapter 1:**
>
> This chapter explains the options and requirements for determining the geographic scope of your GHG emissions report.
>
> **Information you will need:**
>
> You will need basic information about the location of your organization's facilities in the state of California and, if you are reporting all national emissions, throughout the U.S.
>
> **Cross-References:**
>
> It may also be useful to refer to Chapter 2 on organizational boundaries as you examine your geographic boundaries.

II.1.1 Reporting National and California-Based Emissions

The first step in determining what to report to the California Registry is to decide on the geographic scope of your report. You have the option of reporting California-only emissions, or all of your U.S. GHG emissions, which will include California emissions, if any.

Reporting U.S. and California-Only Emissions

The California Registry supports the most comprehensive reporting possible and encourages you to report emissions associated with all of your organization's activities in the United States. If you choose to report your U.S. emissions, you will also need to specifically report your California-based emissions. The California Registry's web-based reporting software is designed to capture your organization's U.S. and California emissions separately so reporting both is easy. Alternately, participants can begin the program by reporting California emissions only and later move to U.S. reporting. If you are reporting at the national level but do not presently have any emissions in California, you must report zero California emissions.

At this time the California Registry will store but does not accept verification information on emissions released by sources outside of the United States.

Reporting California-Only Emissions

If you do not have operations, or do not wish to report your emissions outside California, please report your emissions for California-only. To estimate your California-only emissions you must identify those sources within your organization located in California. Emissions associated with the electricity purchased and consumed in buildings and manufacturing processes occurring in California should be included in the calculation of California-only emissions, regardless of the likely location of the power generation.

Regarding mobile sources, you should report the total GHG emissions for mobile sources registered in California regardless of whether the vehicles travel inside or outside of the state, or whether vehicle fuel was purchased inside or outside of California. Such vehicles may include those your organization owns or leases (see Chapter 3). Vehicles registered by the California Department of Motor Vehicles are considered to be based in California.

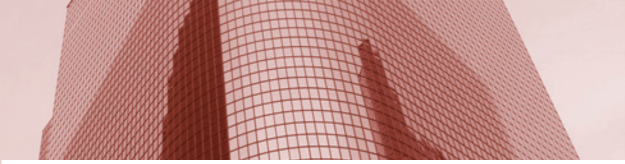
Organizations without California Emissions

If you do not have emissions in California, but wish to report to the California Registry, you must report your California emissions as zero. You are able to report to the California Registry and have this information verified, although you may also be assessed an additional registration fee to help cover the State's costs in overseeing verification of the non-California data.

Determining Whether to Report California-Only or U.S. Emissions

There are several reasons why you may wish to complete a U.S. report of your organization's emissions, such as:

- An existing environmental management system already captures emissions at the national-level;
- It will help you prepare for a future federal regulatory regime;
- Corporate decision-making must look at the "big picture" when making efforts to improve efficiency and make least-cost reductions in GHG emissions;
- It enhances your credibility to investors and customers; and
- Environmental stewardship goals are nationwide (and often worldwide).




You may also report only California-based emissions. Examples of the rationale for taking this approach include the following:

- A participant has only California emissions;
- Completing a report for California offers a good learning experience for implementing a more comprehensive national or international corporate accounting scheme in the future;
- Conducting nation-wide accounting is simply too complex and burdensome at this time; and
- The participant owns and controls 100% of all operations in California, while having only partial ownership in operations outside of California, making California-only reporting more straightforward and less burdensome.

II.1.2 Reporting Worldwide Emissions

The California Registry does accept standardized GHG emissions data from operations outside the U.S., and participants can gather and store data in CARROT. However, the California Registry does not have Board-approved reporting and verification protocols for international data; thus, international GHG emissions data are not verified at this time.

II.1.3 Example: Determining Geographic Boundaries

The following example describes how geographic boundaries impact a company's GHG inventory.

An Express Mail Delivery Company with a Fleet Based Inside and Outside of California

An express mail delivery company operates a fleet of 1,000 vehicles, both inside California and outside the state; 350 of the vehicles are registered in California and 650 are registered outside of California.

If the express mail delivery company is reporting California-only emissions, they would report emissions for only the 350 vehicles registered in California.

If the company is reporting its U.S. emissions, they would report the emissions associated with the 350 California-registered vehicles, and separately report the emissions associated with the 650 non-California-based vehicles.

Chapter 2 Organizational Boundaries

> Who should read Chapter 2:
>
> Chapter 2 applies to all participants.
>
> What you will find in Chapter 2:
>
> This chapter considers the options and requirements for determining the organizational scope of your GHG emissions report.
>
> Information you will need:
>
> You will need information that will help you determine which sources of emissions are to be included in your organizational structure and operations, including information about joint ventures, subsidiaries, and similar entities.
>
> Cross-References:
>
> It may also be useful to refer to Chapter 1 on geographic boundaries and Chapter 3 on operational boundaries as you examine your organizational boundaries.

II.2.1 Defining Your Entity

Once you have determined the geographic boundaries of your report, you should identify the significant emissions for each calendar year within those boundaries that are attributable to facilities and operations that you own or control. For the purposes of this Protocol, the basic unit of participation in the California Registry is an entity in its entirety, such as a corporation or other legally constituted body, a city or county, a state government agency, a non-profit organization, etc. At a minimum, you must report your entity-wide (total) emissions. However, the California Registry strongly encourages you to report GHG emissions information at the facility- or source-level as part of your entity-level report. Although facility-level reporting may require more data-entry work into CARROT for participants, it will provide a more detailed and comprehensive picture of your emissions profile and could reduce verification costs.

II.2.2 Reporting Options and Organizational Boundaries

To establish your organizational boundary, you should evaluate all operations, facilities, and sources that fall within your chosen geographic boundary. For those operations and facilities that are wholly-owned, you should report all of the associated emissions. For those operations or facilities in which you have a partial ownership share or working interest, hold an operating license, lease, or otherwise represent joint ventures or partnerships of some kind (both incorporated and unincorporated), you have two options for determining the GHG emissions you should report:

Option 1 – Management Control: Report 100% of the emissions from operations, facilities, and sources that your organization controls.

If you choose to use the management control approach, the California Registry requires participants to determine control based on financial or operational criterion, which must be consistently applied to all operations, facilities, and sources to determine whether or not the associated emissions fall within your organizational boundary.[1]

Option 2 – Equity Share: Report a percentage of the emissions based on your share of financial ownership of an entity, operation, facility or source. Some participants may have contracts or legal agreements that assign ownership of specific GHG emissions or emissions reductions.

Contracts or agreements may serve to clarify your selected organizational boundary. Where you have agreements regarding emission rights or responsibilities, you may wish to disclose this information to the public in the optional section of your emissions report. However, you are required to report your entity-wide emissions using either the management control and/or equity share emissions consolidation approach, regardless of contractual agreements that assign emission rights or responsibilities.

Companies can choose to establish an organizational boundary based upon management control (either financial or operational) or equity share only, but may also report based upon both emissions consolidation approaches. The method chosen must be applied consistently across all operations, facilities, and sources. Once you have selected an approach to define your organizational boundary, the California Registry requires that you use it consistently for each year of reporting.[2]

The consistent use of a single emissions consolidation approach facilitates comparisons of annual emissions

1 Defining management control in either financial or operational terms is consistent with The GHG Protocol; a discussion of the management control criterion and the operational control criterion can be found in section II.2.3.

2 You may in subsequent years choose to report based upon an additional consolidation methodology, but must continue to report according to the initial methodology you select.

reports, helps identify trends in emissions, and supports the establishment of baseline emissions. The consistent use of an approach to set your organizational boundary will also reduce the cost of future verifications.

II.2.3 Reporting Based on Management Control

Management control can be defined in either operational or financial terms. When using management control to determine how to report GHG emissions associated with joint ventures and partnerships you should first select between either the financial or operational criterion, and consistently apply the definitions below in determining how to report these emissions. One or more conditions from those listed below can be used to establish your choice of control approach. If you determine you have control over a particular joint venture or partnership, you should report 100% of the significant emissions of that entity (all of its operations, facilities, and sources). If you determine you do not have control, you should not report any of the emissions associated with the entity.

In most cases, financial control and operational control of an operation, facility or source reside with the same entity. The organization that has financial control typically also has operational control. Consequently, whether or not a joint venture or partnership is deemed to be controlled by your company, and as a result its emissions fall within your organizational reporting boundary, generally will not depend on which of the approaches of control you select.

However, in some sectors such as the oil and gas industry, complex joint ventures and ownership/operator structures can exist where financial and operational control are not vested with the same organization. In these cases the choice to apply a financial or operational definition of control can have a significant impact on what sources must be included in an inventory. In making this decision, participants should take into account their individual situation, and select a criterion that best reflects your actual level of control and the standard practice within your industry. Additionally, industry-specific guidance developed by the California Registry, included as appendices to this reporting protocol, may provide additional guidance on choosing a criterion for determining management control. Table II.2.1 provides an illustration of the reporting responsibility under the management control reporting option.

Financial control is the ability to dictate or direct the financial policies of an operation or facility with the ability to gain the economic rewards from activities of the operation or the facility.

One or more of the following conditions establishes financial control:

- Wholly owning an operation, facility or source.
- Considering an operation to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in your organization's financial statements.
- Governing the financial policies of a joint venture under a statute, agreement or contract.

Table II.2.1 Reporting Based on Management Control

Level of Control of facility/source	Percent of GHGs to Report Under Financial Criterion	Percent of GHGs to Report Under Operational Criterion
Wholly owned	100%	100%
Partially owned with financial and operational control	100%	100%
Partially owned with financial control; no operational control	100%	0%
Partially owned with operational control; no financial control	0%	100%
Not owned but have a capital or financial lease	100%	100%
Not owned but have an operating lease	0%	100%

- Retaining the rights to the majority of the economic benefits and/or financial risks from an operation or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed. These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include your organization casting the majority of votes at a meeting of the board of directors or having the right to appoint/remove a majority of the members of the board in the case of an incorporated joint venture.

Operational control is the authority to develop and carry out the operating policies or health, safety and environmental (HSE) policies of an operation or a facility.[3]

One or more of the following conditions establishes operational control:

- Wholly owning an operation, facility or source.
- Having the full authority to introduce and implement operational and health, safety and environmental policies. In many instances, the authority to introduce and implement operational and HSE policies is explicitly conveyed in the contractual or legal structure of the partnership or joint venture. While in most cases, holding an operator's license is an indication of your organization's authority to implement operational and HSE policies, this may not always be so. If your organization holds an operating license and you believe you do not have operational control, you will need to explicitly demonstrate that your authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

It should be noted that your organization need not be able to control all aspects of operations within a joint venture to have operational control. For instance, making decisions on major capital investments without the approval of other parties in a venture may be beyond the authority of the entity with operational control.

In the case of joint control, two entities each have 50% equity ownership and no stipulations exist to demonstrate that either organization has control of the financial or operating policies of the venture. If you have joint control over a facility and are using financial control as your control criterion, you should report a pro rata share of your emissions based on your economic interest in and/or benefit derived from the operation or activities at a facility. In this case, you would report 50% of the controlled entity's emissions. If you are using operational control as your control criterion, it may be that neither partner has operational control; a separate entity conducting the operation may implement its own operating policies. In such a case, neither partner would report.

Rationale for Choosing Management Control

An important reason for choosing to report emissions based on management control is that when you control how an operation or a facility is managed you are able to control factors such as capital investment and technology choice, how energy is used, and the level of emissions generated. Thus, reporting emissions using the management control approach reflects your ability to implement actions that could reduce GHG emissions. This approach also helps you to monitor the performance of an operation, a facility, and the entity. Most criteria pollutant emission reduction programs, regulations, and trading systems are based on management control rather than equity ownership. When you have management control of an operation or a facility, you typically have greater access to the information and records needed to calculate and report emissions information, helping to minimize the administrative costs of maintaining a GHG emissions inventory.

> Note: Management control is the default method used by CARROT to calculate emissions.

II.2.4 Reporting Based on Equity Share

If you have facilities and operations in which your share of ownership ranges from 1% to 99%, you may choose to report on an equity share basis—either in addition to, or instead of, reporting based on management control. When reporting on an equity share basis, you should include the portion of the emissions from the facility or operations equal to your equity share of the total emissions. If more than one owner of a facility is a participant in the California Registry and one owner chooses to report based on equity share, then each participating owner must agree in advance to also report on an equity share basis. The collective accounting methodologies of multiple owners should ensure that all applicable emissions are reported and no double counting occurs in the reports. Participants will need to provide an attestation of their ownership share, prepared by either a verified legal or financial advisor. This document should identify all owners of the facilities, including their respective shares of ownership. Table II.2.2 provides an illustration of the reporting responsibility under the equity share reporting option.

3 GHG Protocol, 2004.

Table II.2.2 Reporting Based on Equity Share

Level of Ownership	Percent of GHG Emissions to Report
Wholly-owned	100%
Not wholly-owned, but controlled	By equity share
Partially-owned, no control	By equity share

Rationale for Choosing Equity Share

Setting organizational boundaries based on equity share reflects a commercial reality that entities profiting from a business activity typically have an interest in the operation of the activity. Consequently, ownership of GHG emissions could reasonably be based on the level of economic interest in the organization that generated the GHG emissions. In some instances, management control is not always the best measure of "control" or "influence" over a shared facility. Furthermore, with respect to risk, ultimate financial liability is distributed based on equity share. Thus, this approach could allow for a more complete coverage of liability and risk.

II.2.5 Choosing Both Management Control and Equity Share Reporting

Optimally, you should report your GHG emissions using both the management control and equity share approaches. Given the uncertainty of the exact nature of future GHG emissions trading or regulatory regimes, reporting using both methods will provide the greatest flexibility and maximum use of your emissions data in the future.

Also, your choice of a geographic boundary for your report may be affected by the number and diversity of operations and facilities for which you have partial ownership and the method you select for accounting for those emissions. Thus, if you have partial ownership of multiple facilities, you should consider your approach to emissions reporting in light of both your geographic and organizational boundary alternatives. Where you share ownership of operations or facilities, all owners will need to clarify who will report emissions.

II.2.6 Parent Companies, Subsidiaries, and Holding Companies

If your organization is a subsidiary of a corporation or other legally constituted body, you may join the California Registry if your parent organization is not already a member. The parent organization need not participate in the California Registry merely because one or more of its subsidiaries chooses to participate, but members that are subsidiaries must disclose their parent organization to the California Registry.

However, if the parent organization later joins the California Registry, the parent would report emissions from all of its subsidiaries and subsidiaries would not be able to retain separate membership. Holding companies (corporations that are made up of several other corporations) would report following the management control approaches described above. If the holding company controls several subsidiaries, it would report the total emissions from each of its subsidiaries.

II.2.7 Partnerships and Joint Ownership

Situations may exist in which no party in your organization has sufficient management to claim responsibility for reporting. For example, in a Limited Liability Partnership (LLP), it is possible that no single entity would have a controlling or majority equity share. In such a case, the collective partners would come to a mutual agreement to divide the responsibilities for reporting GHG emissions to the California Registry and report accordingly.

For some sectors such as the petroleum industry, it is common to have joint ownership with a single operator. Holding the operating license may not be a sufficient condition for being able to influence the operating policies of an entity or facility. Therefore, you should review all the conditions for management control listed above to determine what emissions you should report.

II.2.8 Leased Facilities/Vehicles and Landlord/Tenant Arrangements

Reporters shall account for and report emissions from leased facilities and vehicles according to the type of lease associated with the facility or source and the organizational boundary approach selected. This guidance applies to California Registry participants that rent office space (i.e., tenants), vehicles, and other facilities or sources (e.g., industrial equipment).

There are two types of leases[4]:

- **Finance or capital lease:** If you have an asset under a finance or capital lease, the California Registry considers this asset to be wholly-owned by you.
- **Operating lease:** If you have an asset under an operating lease, such as a building or vehicle, the California Registry considers this asset to be under your operational control but you do not have any financial risk or reward from owning the asset.

The California Registry considers any lease that is not a finance or capital lease to be an operating lease. In most cases, operating leases cover rented office space and leased vehicles, whereas finance or capital leases are for large industrial equipment.

Short-term rental agreements (e.g., daily car rentals) do not constitute financial or operational control, and therefore emissions from short-term rentals should not be included in your inventory. Emissions from short-term rental equipment may be reported optionally.

Reporting Emissions from Leased Assets

You shall account for and report emissions from a facility/source under a finance or capital lease as though it were an asset wholly-owned and controlled by your company or organization, regardless of the organizational boundary approach selected.

With respect to facilities/sources under an operating lease (e.g., most office space rentals and vehicle leases), the organizational boundary approach selected will determine whether reporting the asset's associated emissions is required or optional. If the organizational boundary approach is either the equity share approach or the financial control criterion under the management control approach, then reporting the emissions from a facility/source with an operating lease is optional. On the other hand, if you choose the operational control criterion under the management control approach then you are required to report emissions from assets for which you have an operating lease.

Please note that if you are defining your organizational boundaries using operational control and are reporting indirect emissions from electricity use in leased office space, you should only report "usable space" (i.e., the space that you have management control of and occupy). Usable space is calculated from the total "rentable space" minus "common space". Common space may include areas such as lobbies and restrooms. See Chapter 6, Section III.6.2 for more information.

Reporting Natural Gas Use for Leased Office Spaces

Organizations that lease buildings or office spaces that are not separately metered for natural gas use are not required to report the direct emissions associated with natural gas use. No member of the California Registry should report estimated direct emissions. All publicly reported direct emissions should be based on directly metered or measured data sources.

You may, however, choose to report estimated natural gas use optionally. If you wish to report your estimated natural gas use optionally, you may use CARROT's emission category: *Optionally Reported* - Subcategory: *Estimated Natural Gas Usage*. This feature allows you to use CARROT's built-in calculation tools, but classifies the data as optional.

Please note that if you are a building owner that occupies only part of a building's usable space, you should report 100% of the emissions from stationary combustion of natural gas for the entire building because you would have both operational and financial control of this emission source.

Table II.2.3 provides guidance on who is required to report emissions from leased assets for various emission sources under each control approach.

II.2.9 Accounting for Structural Changes

Your emissions report should represent a "snapshot" of what your organization's emission sources are at the end of each calendar year. Thus, when structural changes (e.g., mergers, acquisitions, divestitures, outsourcing, and insourcing) occur during the middle of the year, your emissions report should be calculated to reflect that change for the entire year, rather than only for the remainder of the reporting period after the structural change occurred. For example, if your organization acquires a company in June, you should report the emissions from that company for January – December, not June – December. Alternately, if your organization divests a company in June, you should not report any emissions from that company for the entire calendar year.

If emission changes are due to organic growth or decline (building a new facility, shutting down a facility), you must report actual emissions associated with those operations. For instance, should you close a facility in September, you would report the emissions from January to its close.

4 Financial Accounting Standards Board, Statement of Financial Accounting Standards, No. 13. Accounting for Leases. 1976.

Table II.2.3 Reporting Emissions from Leased Assets

Who Reports	Reporting Criteria			Optionally Reported Emissions
	Management Control		Equity Share	
	Operational Control	Financial Control		
Electricity				
Tenant	✓			
Landlord		✓	✓	
Natural Gas				
Tenant	✓ (if metered individually for tenant's space AND tenant has control of use)			✓
Landlord	✓ (if NOT metered individually for tenant's space)	✓	✓	
HFCs				
Tenant				✓
Landlord	✓	✓	✓	
Mobile Emissions (cars, etc.)				
Vehicle Renters (Company-rented)				✓
Vehicle Lessors (Company-leased)	✓			
Vehicle Owners (Company-owned Vehicles)	✓	✓	✓	
Owners of Personal Vehicles (including personal vehicles used for business purposes)				✓

II.2.10 Examples: Management Control vs. Equity Share Reporting

The following examples are provided to assist you as you determine whether to report using the management control or the equity share basis. Remember, although these examples are provided for individual facilities, you should choose both approaches or either the management control or the equity share approach for your report in its entirety.

Example II.2.1 Companies with Ownership Divided 60%-40%

Company A has 60% ownership and management control, under both the financial and operational control criterion. Company B has 40% ownership of the facility, and does not have management control

Under either criterion for management control, Company A would report 100% of GHG emissions. It has financial control based on its 60% share and there are not other provisions that vest operational control with its minority partner. Under equity share, Company A and Company B would report 60% and 40% of GHG emissions respectively, based on their share of ownership and voting interest.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	60% ownership & voting interest	100%	100%	60%
Company B	40% ownership & voting interest	0%	0%	40%

Example II.2.2 Companies with Ownership Divided 60%-40% and Voting Interests Divided 45%-55%

Company A has 60% ownership of the facility and a 45% voting interest. Company B has 40% ownership of the facility and a 55% voting interest. Company B is also explicitly named as the operator and has the authority to implement its operational and HSE policies. Company B has management control (according to both the financial and operational criteria).

Under management control (either financial or operational criterion), Company B would report 100% of GHG emissions and Company A would report none, because Company B has a majority voting interest. Under equity share, Company A would report 60% of GHG emissions and Company B would report 40%, based on ownership share.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	60% ownership & 45% voting interest	0%	0%	60%
Company B	40% ownership & 55% voting interest	100%	100%	40%

Example II.2.3 Two Companies with 50% Ownership Each

Company A and Company B each have 50% ownership of the facility. Company B has the authority to implement its operational and HSE policies, but all significant capital decisions require approval of both Company A and Company B. Each reports 50% of GHG emissions under the financial criterion of management control and equity share. Under the operational criteria of management control, Company B reports 100% of the facility's emissions while Company A reports 0%.

Example II.2.4 Three Companies with Ownership Divided 55%-30%-15%

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	50% ownership & voting interest	50%	0%	50%
Company B	50% ownership & voting interest	50%	100%	50%

Company A has 55% ownership of the facility, Company B has 30% ownership of the facility, and Company C has 15% ownership. The majority owner has the authority to implement its operational and HSE policies.

Under either criterion of management control, Company A would report 100% of GHG emissions because it holds a majority interest in the control of the facility, and Companies B and C would report no emissions. Under equity share, each company would report according to its equity share of ownership and voting interests.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	55% ownership & voting interest	100%	100%	55%
Company B	30% ownership & voting interest	0%	0%	30%
Company C	15% ownership & voting interest	0%	0%	15%

Chapter 3 Operational Boundaries: Required Direct and Indirect Emissions

> Who should read Chapter 3:
>
> Chapter 3 applies to all participants.
>
> What you will find in Chapter 3:
>
> This chapter provides guidance on determining what direct and indirect GHG emissions your organization must report to the California Registry.
>
> Information you will need:
>
> You will need information about the size and nature of GHG-emitting operations throughout your organization in order to determine which emissions are directly and which are indirectly caused by your organization.
>
> Cross-References:
>
> It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, and de minimis and significant emissions addressed in Chapter 5.

The next step in compiling your GHG emissions report is to divide your emission sources into emission source categories. Emission sources produce either direct or indirect emissions.

Direct emissions are those emissions from sources that are owned or controlled by your organization. You must report all of your direct emissions. These emissions originate from:

- Mobile combustion sources (e.g., from cars, trucks, rail, air, and other transport) owned or leased by your organization and used for moving raw materials, finished products, supplies, or people;
- Stationary combustion sources used for the production of electricity, steam, or district heating and cooling;
- Process emissions that occur during the production of cement, adipic acid, and ammonia, as well as emissions from agricultural processes; and
- Fugitive sources, for example methane leaks from pipeline systems or leaks of HFCs from air conditioning systems.

Indirect emissions are emissions that occur because of your organization's actions, but are produced by sources owned or controlled by another entity.[1] You should report all of your company's indirect emissions from the following sources:

- Purchased and consumed electricity;
- Purchased and consumed steam; and
- Purchased and consumed district heating or cooling.

You are also encouraged, but not required, to report indirect GHGs from other activities of your organization that produce emissions, but do not fall within your organizational boundary. This could include, for instance, employee commuting and business travel, off-site waste disposal, and other emissions resulting from your demand for goods and services each year. The California Registry currently provides limited guidance for estimating emissions from these optional indirect sources, but identifies some existing tools to help you in this process. More information is available in Chapter 11.

II.3.1 Double Counting Direct and Indirect Emissions

The California Registry recognizes that a company accounting for its indirect emissions may double count the direct emissions from a separate entity. For example, the indirect emissions from electricity use in a participant's inventory double counts the direct emissions from the electricity generator that produced the participant's power. The California Registry requires participants to inventory both direct and indirect emissions to create a comprehensive emissions profile of the entity. This yields a complete picture of the emissions produced by sources owned or controlled by the participant and the emissions produced as a consequence of the participant's activities. The California Registry strives to avoid confusion by requiring participants to report direct and indirect emissions separately.

Double counting direct and indirect emissions does not misrepresent a company's emission profile. It only impacts a company in terms of how the reported information is used. For instance, emissions regulatory regimes could impose limits on emissions that apply to direct or indirect emissions.[1]

1 The GHG Protocol, 2004.

Chapter 4 Establishing and Updating a Baseline

Who should read Chapter 4:

Chapter 4 applies to all participants.

What you will find in Chapter 4:

This chapter considers the options and requirements for determining your organization's baseline.

Information you will need:

You will need information that will help you determine the basis for selecting a baseline year, such as historic emissions data to determine the earliest year (back to 1990) for which you can assemble the required emissions data to complete an emissions report. You will also need to consider any information, if applicable, describing new or recent mergers and acquisitions, divestitures, outsourcing and insourcing of services, and other changes to your organization affecting your total emissions.

Cross-References:

You will need to refer to all applicable chapters relating to quantifying your emissions (Chapters 5-11) in determining your baseline.

II.4.1 Establishing Your Baseline

A baseline is a datum or reference point against which to measure GHG emissions increases and decreases over time. Baselines are used in a regulatory context to establish a clear threshold for compliance and non-compliance. Setting a baseline also allows participants to scale structural changes to their organization back to a benchmark emission profile. This aspect of baselines is called "normalization". For example, as explained below, an acquisition of a company could dramatically increase a participant's emissions relative to previous reporting years. To account for the impact on its emissions profile due to acquisition, a participant would adjust its baseline to incorporate the additional emissions associated with the acquired company, thereby showing that the change in emissions occurred because of structural changes.

Participants select their baseline according to the year that best represents their standard emissions profile. In the context of the California Registry, a baseline is a "base year" that serves as a benchmark to compare emissions produced by an entity over time. The baseline is adjusted to reflect structural changes in your organization.[1] A baseline may also change if there are fundamental changes in generally accepted GHG emissions accounting methodologies.

Although the California Registry strongly encourages participants to set a baseline, you are not required to do so. However, if you choose not to establish a baseline, reviewers of your emission trend might compare successive reporting years back to your first year of reporting, regardless of whether it is indicative of your current structure or operating conditions.

A participant may begin reporting emissions to the California Registry for any year from 1990 forward; likewise it can establish as its baseline any reporting year from 1990 forward. After establishing a baseline participants should report verified emissions results for each subsequent year. If an organization's participation in the California Registry lapses temporarily, it must report emissions for all intervening years upon renewing its participation or establish a new baseline. If its boundaries do not change significantly, the baseline will remain fixed over time.

II.4.2 Rationale for Setting a Baseline

There are several issues to consider when deciding whether to establish a baseline, including:

- **Data certainty** – do you have sufficient data to verify your emissions against the requirements in the General Reporting Protocol for the baseline year?
- **Comparable organizational structure** – is your organization sufficiently comparable in its composition and structure to support a meaningful comparison with the baseline year?
- **Relative emission levels** – which year minimizes or maximizes your emissions relative to most recent levels, and what are the benefits of doing so?

Your baseline should not be adjusted for the organic growth or decline of your organization. Organic growth or decline refers to the increase or decrease in production output, changes in product mix, plant closures, and the opening of new plants that are not the result of changes in the structure of the participant's organization or the result of shifting operations into or out of California or the U.S.

1 In the GRP, baselines refer strictly to entity-level baselines. The GRP does not provide guidance on setting project-level baselines. Participants should refer to the California Registry project protocols for direction on this activity.

Many organizations experience growth and thus their total absolute emissions will increase from year to year, regardless of their organization's operational efficiency. Such organizations, in addition to reporting their total emissions, may also elect to report an efficiency metric, that measures GHG emissions per unit of performance or output compared to the baseline ratio (e.g., CO_2/ft^2 of office space, CO_2/customer, CO_2/kWh, CO_2/$ of revenue, etc.) A list of industry-specific metrics is provided in Appendix F.

II.4.3 Updating Your Baseline

Conditions for Updating Your Baseline

The purpose of a baseline is to compare your organization's emission levels from a point in the past. To allow for this comparison, you must have comparable boundaries over time. If your organization's boundaries change with time, you will need to adjust baseline emissions to permit accurate comparison.[2] This Protocol identifies six circumstances that would require you to update your baseline:

Structural Changes in Your Organization

1. Mergers and acquisitions
2. Divestitures
3. Outsourcing – contracting activities to outside parties that were previously conducted internally
4. Insourcing – conducting activities internally that were previously contracted to outside parties

Shifting of Emissions Sources

5. A shift in the location of an emission source (e.g., due to relocating operations into or out of the U.S. or the State of California, depending on your geographic boundaries)

Improved GHG Accounting Methodologies

6. Fundamental changes in generally accepted GHG emissions accounting methodologies (e.g., significant changes in emission factors or understanding of global warming potential). Please note that you do not need to update your baseline due to changes in electricity emission factors (e.g., switching from eGRID emission factors to utility-specific emission factors or changes in the electricity emission factors between reporting years, as these emission factors are expected to change from year to year based on the power mix for your region)

All required sources of direct and indirect emissions must be included in a participant's entity-wide baseline for reporting and adjustment purposes. However, participants identify and account for direct and indirect emissions separately. Thus, participants may consider tracking both types of emissions separately in terms of a baseline. Both direct and indirect emission baselines are meaningful for the purposes of the California Registry.

2 Participants also have the option to change their baseline at their discretion.

Threshold for Updating a Baseline

For many organizations – particularly large ones – mergers, acquisitions, and divestitures, as well as the other listed organizational changes, are common occurrences. Rather than requiring baseline adjustments whenever any changes occur in your organization, however insignificant, you need only adjust your baseline whenever you estimate that the cumulative effect of such changes affects your organization's total reported emissions by plus or minus 10% relative to the baseline. You may adjust your baseline every year, if you wish. You do not need to adjust your baseline when emissions change by plus or minus 10% at any individual facility unless this facility-level change also affects your total entity emissions by plus or minus 10%.

In some situations, year-to-year changes to total emissions resulting from structural or other changes to your organization may fall below the 10% threshold for updating your baseline. You will need to update your baseline if and when the cumulative effect is greater than 10%. An example of cumulative changes to total emissions is provided in Example II.4.7.

When you specify a baseline, for every year after the baseline year, your verifier will also need to verify that your total emissions have not changed by more than 10% from the baseline due to any cause except organic growth. This is intended to provide a check that you are correctly tracking and reporting the emissions associated with your organization's structure.

Options for Updating a Baseline

For members who have chosen to set a baseline year and who have surpassed the threshold for updating their baseline (plus or minus 10%), there are a few options to consider. You could 1) remove the baseline year and continue to report with no set baseline, 2) remove the baseline year and choose the current year as a new baseline year, or 3) update the baseline year to reflect the cumulative change to your organization. This would require updating and re-verifying all intervening years as well.

Timing for Updating a Baseline

When significant structural changes occur during the middle of the year that trigger a baseline update, your baseline should be recalculated for the entire year, rather than only for the remainder of the reporting period after the structural change occurred. For example, if your organization acquires a company in June, then the emissions associated with the acquisition starting from January 1 of the baseline year should be added to your baseline, not just the emissions from June – December. Similarly, all years following the baseline year, including

the current year emissions (the year that the structural changes occur) should be recalculated for the entire year to maintain consistency with the baseline recalculation.

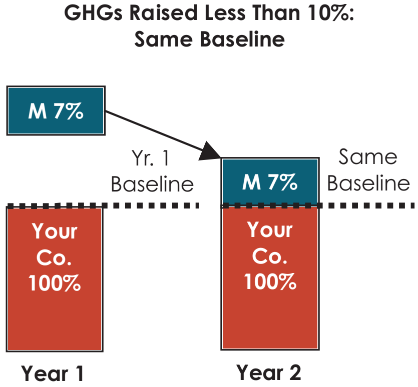
Updating a Baseline for Facilities That Did Not Exist in the Baseline Year

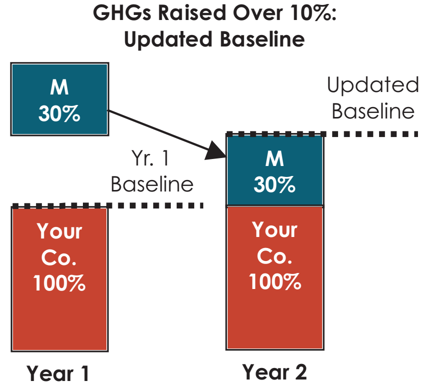
Baseline emissions are not recalculated if your organization makes an acquisition of (or insources) operations that did not exist in its baseline year. There should only be a recalculation of historic data back to the year in which the acquisition came into existence. For instance, if your baseline is 2004 and you acquire a facility in 2008 that began operations in 2006, you would revise your 2006 and 2007 emissions reports to add the associated emissions. However, you would not adjust your 2004 baseline. The same applies to cases where your organization divests (or outsources) operations that did not exist in the baseline year.

II.4.4 Examples: Updating Your Baseline

Example II.4.1 Mergers and Acquisitions

Your organization merges with Mergitrex, raising your total GHG emissions by over 10%.



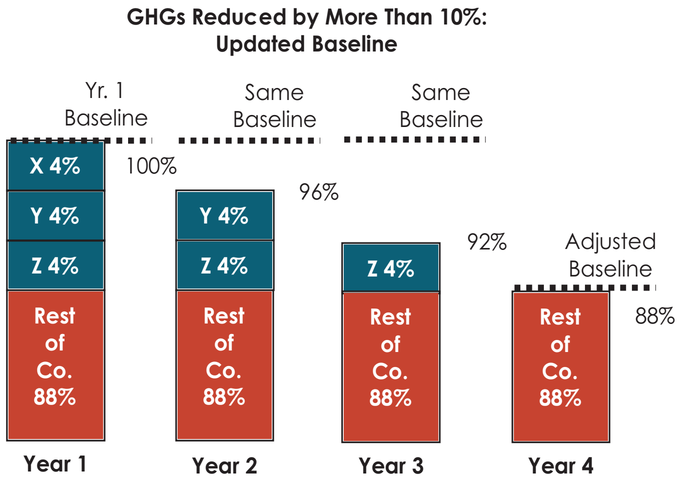


Adjust your baseline emissions to include Mergitrex's baseline emissions (provided Mergitrex existed in your baseline year). If Mergitrex did not exist in the baseline year, do not adjust your baseline emissions. If your merger with Mergitrex led to less than a 10% increase in GHG emissions, do not adjust your baseline emissions unless the acquisition, when combined with other non-organic changes to the organization, changes your annual emissions by more than 10%.

If Mergitrex does not have sufficient data to establish baseline emissions for your organizations baseline year, you will need to select a new baseline year for which both companies have sufficient data to allow the baseline emissions to be verified.

Example II.4.2 Divestitures

Your organization divests three divisions over the second, third, and fourth reporting years. Each of these divisions account for 4% of your GHG emissions, for a 12% total reduction in emissions by year four.



Because the cumulative effect of these divestitures reduces your company's emissions by more than 10% in year four, you will need to adjust your baseline by subtracting the emissions of the three divisions from those reported during your baseline year and adjust the baseline accordingly.

Example II.4.3 Outsourcing

Your organization contracts out activities previously included in your baseline.

If your organization contracts out activities previously included in its baseline inventory, you should treat these activities similar to a divestiture. Emissions associated with the outsourced activity should now be reported as optional emissions and subtracted from the baseline emissions. If this shift affects your emissions by more than 10%, you should adjust your baseline. There is no need to adjust your baseline for outsourcing of activities that did not exist during your baseline year. As part of your annual GHG emissions reporting, you will attest that your organization has not outsourced any emissions, or, if you have, that these emissions have been subtracted from your baseline or that they fall below the minimal level.

Example II.4.4 Insourcing

Your organization begins to conduct business activities not previously included in its baseline inventory.

Insourcing is the converse of outsourcing. You should treat these activities as an acquisition. Emissions associated with the insourced activity should be reported as direct or indirect depending on the owner of the emissions and not included with optional emissions. If this shift affects your emissions by more than 10%, you should adjust your baseline. You should not adjust the baseline for insourcing of activities that began after your baseline year.

Example II.4.5 Shifting the Location of Emissions Sources

Your organization moves operations out of or into California or the U.S.

If you shift operations outside of California, which reduces the sum of your direct and indirect emissions by 10% or more, subtract the emissions of the shifted operations from your baseline. Shifts of operations into California of 10% or more should be addressed by increasing your baseline to include emissions from those operations. A U.S. baseline should be adjusted similarly for shifts of operations outside or into the U.S. Where you identify leakage or shifting of emissions—where reducing emissions at one location leads to an increase of emissions at another location—because of shifts in the location of your emission sources, you should document the estimated impacts in your annual movement report.

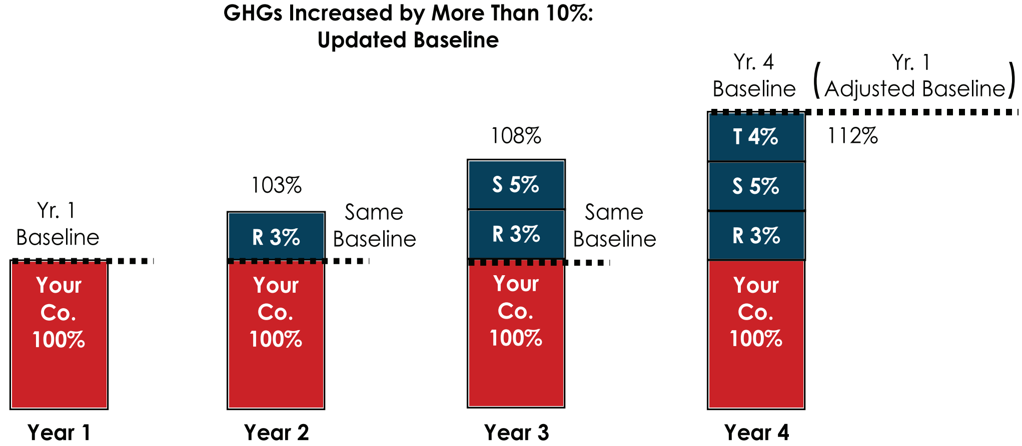
Example II.4.6 Change in Emissions Accounting Methodologies

Your organization employs a new methodology that is approved by the California Registry.

Your baseline emissions should be recalculated for any changes in calculation methodologies if such changes will alter your total emissions in the current reporting year more than 10%. This ensures a comparative time-series of emission estimates.

Example II.4.7 Cumulative Changes to Total Emissions

Your organization acquires three companies over three years, raising your GHG emissions by 12%.



Your company acquires Reyes Rockets, Sierra Spaceworks, and Trinity Telescopes in reporting years two, three, and four representing GHG emission increases of 3%, 5%, and 4%, respectively. While these acquisitions individually represent less than the required 10% increase for a baseline adjustment, they amount to a 12% cumulative increase in total emissions. Thus, you would be required to update your baseline in year four (assuming each company existed in your baseline year).

Part III Quantifying Your Emissions

Having determined your geographic, organizational, and operational boundaries and your emission baseline (if you choose to have one), you are ready to begin estimating your organization's overall emissions. For many participants, the only significant emissions of GHGs you will have to report are indirect emissions from the purchase and consumption of electricity. Thus, this Protocol begins its series of emissions estimation methods with indirect emissions from electricity consumption. Next, it provides guidance for the next most common emission sources for participants: direct emissions from mobile sources. The following chapters provide guidance on calculating emissions from other required sources and optional sources.

Part III provides you with the technical methodologies needed to quantify the GHG emissions you will be reporting to the California Registry.

Chapter 5 provides an explanation of de minimis and significant emissions. De minimis emissions represent a quantity of GHG emissions from one or more sources and one or more gases, which, when summed, equal less than 5% of your organization's total emissions.

Chapters 6 though 11 provide estimation methods for the following categories of emissions:

- Chapter 6 – Indirect Emissions from Grid-Delivered Electricity Use
- Chapter 7 – Direct Emissions from Mobile Combustion
- Chapter 8 – Direct Emissions from Stationary Combustion
- Chapter 9 – Indirect Emissions from Imported Steam, District Heating or Cooling and Electricity from a Co-Generation Plant
- Chapter 10 – Direct Emissions from Manufacturing Processes
- Chapter 11 – Direct Fugitive Emissions

Chapter 12 provides guidance on efficiency metrics and reporting emissions outside of your entity's influence, which the California Registry considers Optional Reporting.

Chapter 5 De Minimis Emissions and Significance

Who should read Chapter 5:

Chapter 5 applies to all participants.

What you will find in Chapter 5:

This chapter provides guidance on determining what emissions are significant, what emissions can be classified as de minimis, and estimating de minimis emissions.

Information you will need:

You will need information about the size and nature of GHG-emitting operations throughout your organization, particularly to be able to identify emissions sources that would amount to less than 5% of your company's total emissions.

Cross-References:

It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, respectively, operational boundaries considered in Chapter 3, and all relevant quantification issues raised in Chapters 6-11.

The rules, methodologies, and standards in this Protocol are designed to support the reporting of GHG emissions in a manner that minimizes the reporting burden and maximizes the benefit of standardized GHG emissions data.

III.5.1 Understanding De minimis and Significant Emissions

For the purposes of this Protocol, de minimis emissions are a quantity of GHG emissions from any combination of sources and/or gases, which, when summed equal less than 5% of your organization's total emissions. Significant emissions are any emissions of GHGs that are not de minimis in quantity when summed across all sources of your organization.

For many participants, identifying and quantifying all of their GHG emissions according to the methodologies presented in this Protocol would be unduly burdensome and not cost-effective. Some participants may operate hundreds, if not thousands, of small facilities where the known emissions—including, for example, indirect emissions from electricity consumption or direct emissions from motor vehicle operation—are a small fraction of larger emissions sources from industrial activities. To reduce the reporting burden, the California Registry requires that entities calculate at least 95% of their emissions according to the Protocol's methodologies. Thus, if necessary, up to 5% of emissions can be classified and reported as de minimis. However, the California Registry strongly encourages entities to report 100% of their emissions according to the methodologies laid out in the Protocol when possible.

III.5.2 Rationale for Calculating De Minimis Emissions

You must identify and report all sources of emissions in your inventory. For significant sources, you must calculate these emissions using required methodologies. For insignificant sources (i.e., potential de minimis sources), you may use a rough, upper bounds estimate to determine the amount of emissions that are de minimis. In the first year, you need to identify what sources fall into the de minimis pool and their estimated total emissions. This information must be disclosed in your emissions report, and reviewed and accepted by your verifier. In subsequent years, if these emissions do not change significantly, you can hold these assumptions constant and your verifier may not need to re-examine your estimates. However, you must continue to report your de minimis sources in CARROT each year.

For example, a participant estimates they emit about 1,000 metric tons of CO_2 each year. Most of these emissions come from an on-site heating and cooling system that services their buildings. In addition, this participant also has one company car that is driven about 20,000 miles each year. This participant estimates that between 800 and 1,000 gallons of gasoline are consumed by this car each year. Taking the upper estimate of 1,000 gallons, the participant calculates the emissions from this source as 8.8 metric tons of CO_2/year, and finds that this amount falls below the de minimis threshold of 5% or 50 tons CO_2/year.

The participant can report this emission source as de minimis in CARROT and provide this estimation to the verifier, along with vehicle records showing the actual miles traveled of the car. In subsequent years, where the operation patterns do not change significantly, the participant can continue to declare the emissions from this source de minimis, and will need to re-calculate this information only every three years.

You may use alternative methods to demonstrate that emissions are de minimis. For example, if your emissions


come only from electricity and fuel consumption, it would be sufficient to show that the emission factors for methane and nitrous oxide, when multiplied by their global warming potentials and added together, are less than 5% of the corresponding emission factor for carbon dioxide. Assuming you deemed no other type of emissions to be de minimis, the total de minimis emissions would be less than the 5% threshold. You should base your de minimis assumptions on the IPCC 's Second Assessment Report (SAR) global warming potential values.

Your estimations and assumptions in calculating your de minimis emissions will need to be disclosed in your emissions report and provided to and verified by your verifier. If your operations do not change significantly from year to year, you will only need to re-calculate and have verified your de minimis emissions every three years.

III.5.3 Identifying De Minimis Emissions

The sources and gases that will be de minimis will vary from participant to participant. For example, fugitive GHG emissions may be de minimis for many participants but will likely be significant for participants involved in the transportation and distribution of natural gas. Similarly, many participants may choose to select non-CO_2 gases as de minimis since non-CO_2 gas emissions are not significant for many operations.

As demonstrated in the examples on the following pages, you have some discretion in identifying sources as de minimis. As Examples III.5.1 and III.5.2 demonstrate, there may be instances where you identify multiple sources as de minimis, which, when added together, equal less than 5% of your emissions. Example III.5.3 illustrates how emissions of different kinds of gases can also be considered de minimis if their combined total is less than 5% of your overall emissions.

III.5.4 Using CARROT to Document De Minimis Emissions

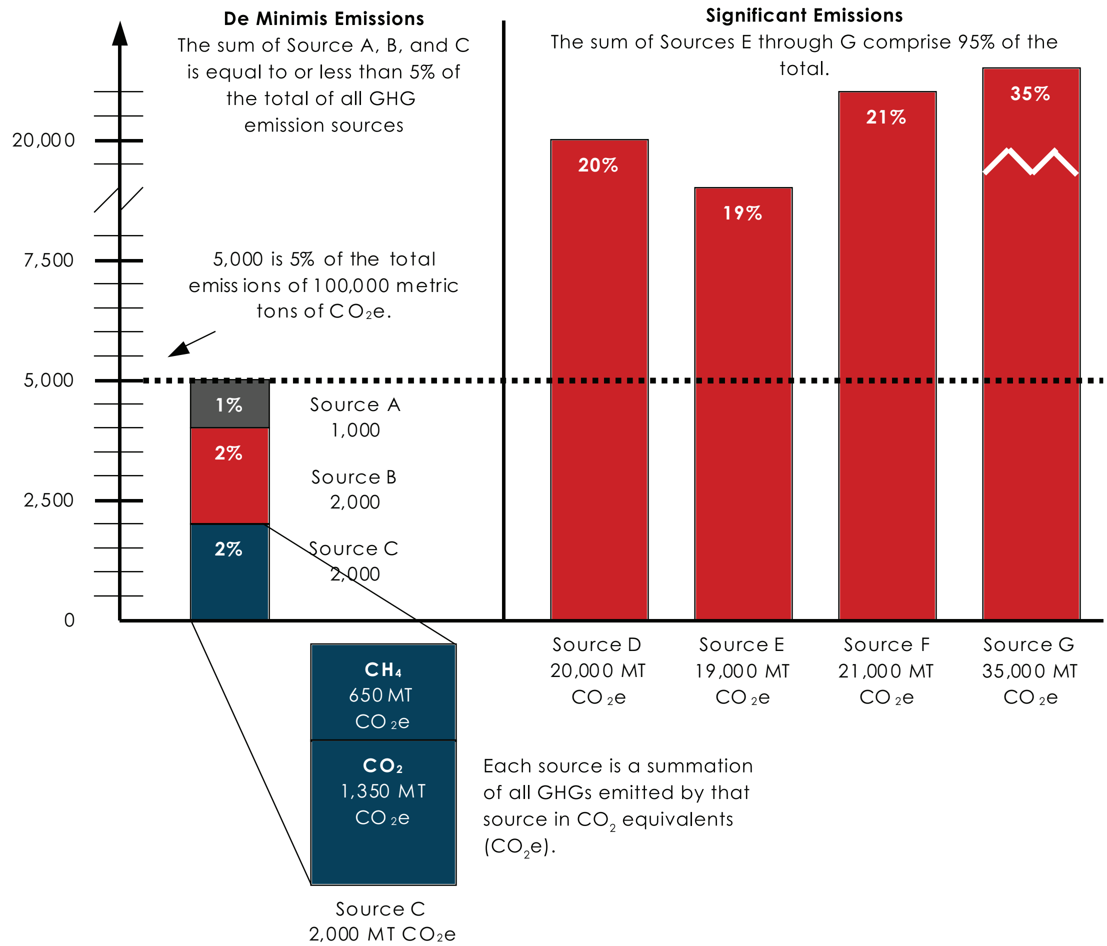
CARROT helps you to calculate and track your de minimis emissions over time. In the first year you report using CARROT, you will enter information to calculate all of your emissions. Once you have reported your inventory, you can designate any combination of individual sources or gases as de minimis. CARROT will then track this information for you, and report it in a category separate from the rest of your emissions.

III.5.5 Examples: Determining De Minimis

Example III.5.1 All Small Sources are De Minimis

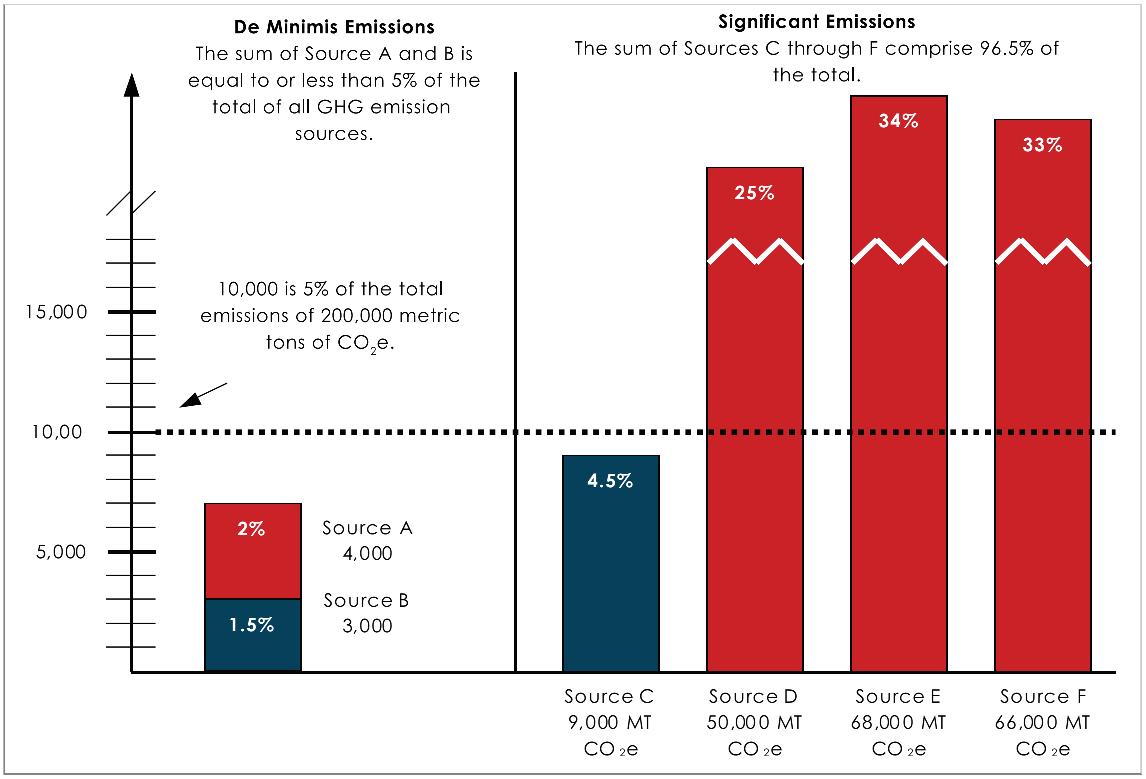
Your company intends to report GHG emissions from seven sources (A through G). You have calculated your total GHG inventory (including de minimis emissions) to determine the 5% threshold. Your total emissions inventory from all seven sources is 100,000 metric tons CO_2e. Therefore, the 5% de minimis threshold is 5,000 metric tons CO_2e. This means that you can decide which 5,000 metric tons of emissions you want to classify as de minimis.

The sum of the GHG emissions from Source A, Source B, and Source C is equal to 5% of your company's total emissions or 5,000 metric tons. As a result, you may choose to report emissions from Source A, Source B, and Source C as de minimis sources. Note, however, that each source is the sum of all GHGs emitted for that source. For example, Source C is a combination of 1,350 metric tons CO_2 and 650 metric tons of CO_2 e from methane, for a total of 2,000 metric tons of CO_2e.



Example III.5.2 Choosing Between Small Sources for De Minimis

Your company intends to report GHG emissions from 6 sources. You have estimated that your total GHG emissions inventory from all 6 sources, including de minimis sources, is 200,000 metric tons of CO_2e. Therefore, your 5% threshold is 10,000 metric tons of CO_2e. You have three sources, Source A, Source B, and Source C, that are each below the 5% threshold. However, you will need to select a combination of sources that, when added together, are less than or equal to the 5% threshold. For example, you may choose to classify Source A and Source B as de minimis. Likewise, you could also choose to classify only Source C as de minimis.



Example III.5.3 Different Sources of CO_2 and CH_4 Emissions are De Minimis

Your company plans to report both carbon dioxide and methane emissions from four sources. You have estimated your total GHG emissions from all four sources at 100,000 metric tons of CO_2e. The emissions from the four sources are as follows:

Source	CO_2 Emissions (metric tons)	CH_4 Emissions (metric tons CO_2e)	Total Source Emissions (metric tons CO_2e)
Source 1	39,900	**100**	40,000
Source 2	29,900	**100**	30,000
Source 3	19,900	**100**	20,000
Source 4	**3,000**	7,000	10,000
Total			100,000
De Minimis Threshold			5,000
De minimis emissions = 3,300 Significant emissions = 96,700			

Chapter 6 Indirect Emissions from Electricity Use

Who should read Chapter 6:

Chapter 6 applies to all participants. Any organization that purchases and consumes electricity from an electric utility should complete this chapter.

What you will find in Chapter 6:

This chapter provides guidance on calculating your indirect emissions from electricity consumption.

Information you will need:

Organizations will simply need to refer to monthly utility electricity bills for information about electricity consumed.

Cross-References:

This chapter may be useful in completing Chapter 9 on quantifying indirect emissions from co-generation, steam or district heating and cooling.

III.6.1 Calculating Indirect Emissions from Electricity Use

Nearly all companies are likely to have some indirect emissions associated with the purchase and use of electricity. In some cases, indirect emissions from electricity use may be the only GHG emissions that a company will have to report. To calculate indirect emissions from electricity use, you should follow this simple five-step process:

1. Determine your annual electricity use in each applicable state or region where you have operations;
2. Select the appropriate electricity emission factors that apply to the electricity source used;
3. Determine your total annual emissions in metric tons;
4. Convert non-CO_2 gases to carbon dioxide equivalent (CO_2e); and
5. Total the sum of all CO_2 and CO_2e gases emitted from electricity use.

The generation of electricity through the combustion of fossil fuels typically yields carbon dioxide and, to a much smaller extent, nitrous oxide and methane. This Protocol provides annual emission factors for all three.

Step 1: Determine annual electricity consumption.

Reporting indirect emissions from electricity consumption begins with determining annual electricity use. The preferred method for establishing annual electricity use relies on the energy use information provided by the electric utility company. A participant's monthly utility bills contain the number of kilowatt-hours consumed. A kilowatt-hour (kWh) is a measure of the energy used by electric loads, such as lights, office equipment, air conditioning or machinery.

Depending on the organization of your company and its facilities, you may need to aggregate multiple electricity bills. Collect your monthly bills and record the kilowatt-hours consumed each month. Then, add together your total kWh per state for the year.

If your electric bill does not begin or end exactly on January 1 and December 31, but spans two calendar years, you must pro-rate your electricity use to properly quantify the emissions for the calendar year being reported; refer to Equation III.6a.

Equation III.6a — Monthly Electricity Use

$$\text{Electricity Use (kWh)} = \left(\text{Electricity Use (kWh) in Period Billed} \div \text{Number of Days in Period Billed} \right) \times \text{Number of Days of Bill Period}$$

To calculate your emissions for January from an electric bill spanning December and January, first, divide your total kilowatt-hours used by the number of days in your billing cycle. Then, calculate the number of days from your bill that fall in January. Multiply the electricity use per day by the number of days in January.

If an organization is unable to obtain energy use information from the utility, the California Registry offers three alternative methodologies for estimating energy consumption. Instructions for following these approaches are provided in Section III.6.2.

Step 2: Select electricity emission factors applicable to the area where the energy was consumed.

An electric grid emission factor represents the amount of GHGs emitted per unit of electricity consumed from the electricity transmission and distribution system, and is reported in pounds per kilowatt-hour or megawatt-hour (lbs/kWh or /MWh). However, as a practical matter it is often very difficult to determine the exact fuel source for your electricity.

Thus, regional/power pool emission factors for electricity consumption can be used to determine emissions based on electricity consumed. If you can obtain verified emission factors specific to the supplier of your electricity, you are encouraged to use those factors in calculating your indirect emissions from electricity generation. If your electricity provider reports an electricity delivery metric under the California Registry's Power/Utility Protocol, you may use this factor to determine your emissions, as it is more accurate than the default regional factor. Utility-specific emission factors are available in the Members-Only section of the California Registry website and through your utility's Power/Utility Protocol report in CARROT.

This Protocol provides power pool-based carbon dioxide, methane, and nitrous oxide emission factors from the U.S. EPA's eGRID database (see Figure III.6.1), which are provided in Appendix C, Table C.2. These are updated in the Protocol and the California Registry's reporting tool, CARROT, as often as they are updated by eGRID.

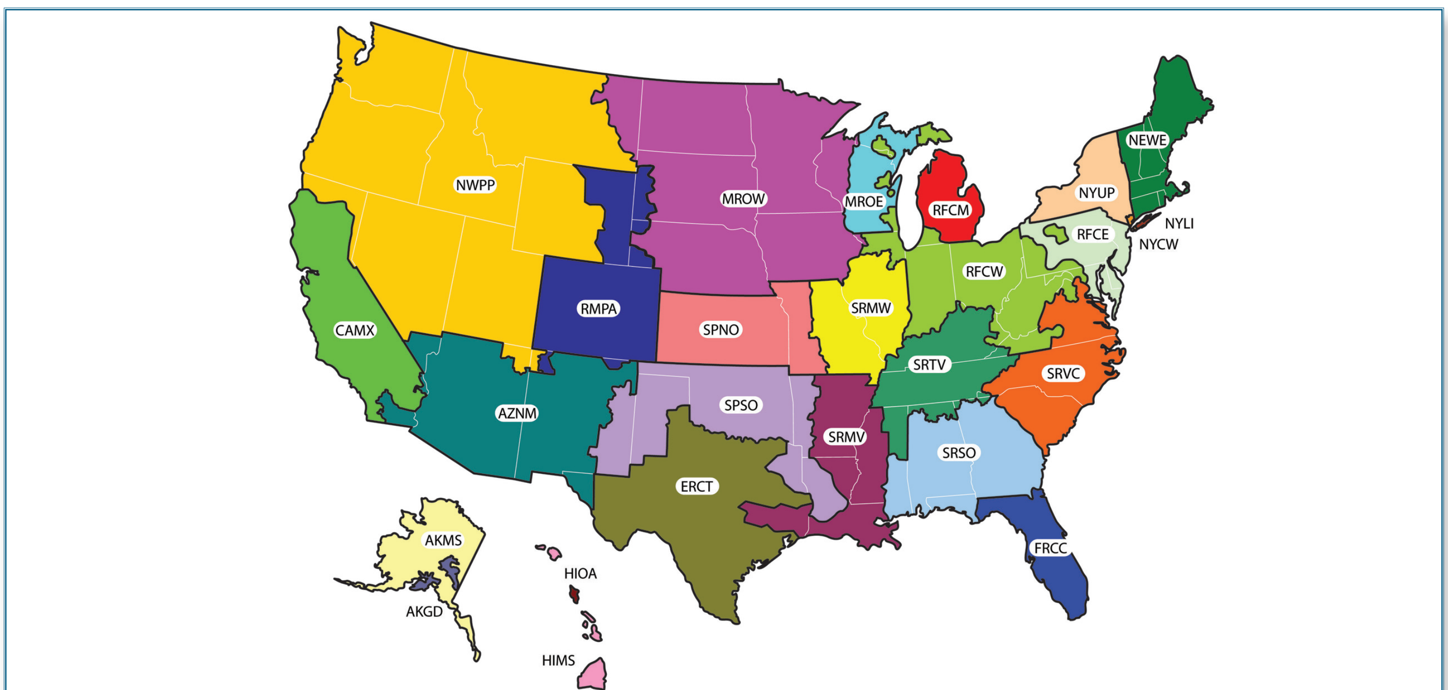
To look up your eGRID subregion using your zip code, please visit U.S. EPA's "Power Profiler" tool at www.epa.gov/cleanenergy/energy-and-you/how-clean.html.

Fuel used to generate electricity varies from year to year, so emission factors also fluctuate. When possible, you should use emission factors that correspond to the calendar year of data you are reporting. CO_2, CH_4, and N_2O emission factors for historical years are available in Appendix E. If emission factors are not available for the year you are reporting, use the most recently published figures.

U.S. EPA Emissions and Generation Resource Integrated Database (eGRID)

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 combined with generation data from EIA to produce 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 encompasses more than 4,700 power plants and nearly 2,000 generating companies. eGRID also documents power flows and industry structural changes.
www.epa.gov/cleanenergy/egrid/index.htm.

Figure III.6.1 eGRID Subregions



Source: eGRID2007 Version 1.1, December 2008 (Year 2005 data).

Step 3: Determine total annual emissions and convert to metric tons.

Multiply your electricity use in kilowatt-hours from Step 1 by the emission factors for CO_2, CH_4, and N_2O from Step 2. To convert pounds into metric tons, divide the total by 2204.62 lbs/metric ton. (See Equation III.6b.) Repeat this step for each region in which you purchased electricity.

Equation III.6b	Total Emissions from Indirect Electricity Use					
Total CO_2 Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs CO_2/kWh)	÷	2,204.62 lbs/metric ton
Total CH_4 Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs CH_4/kWh)	÷	2,204.62 lbs/metric ton
Total N_2O Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs N_2O/kWh)	÷	2,204.62 lbs/metric ton

Step 4: Convert non-CO_2 emissions to CO_2e and sum the total.

To incorporate non-CO_2 gases into your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO_2 equivalent. To do this, multiply the non-CO_2 GHG emissions in units of mass by its global warming potential (GWP). Table C.1 in Appendix C lists the 100-year GWPs to be used to express emissions on a CO_2 equivalent basis. Equation III.6c shows the calculation to determine CO_2e from the total mass of a given non-CO_2 GHG using the GWPs published by the IPCC in its Second Assessment Report (SAR, 1996). If you use CARROT to calculate your emissions, it will automatically perform this calculation for you. Sum your CO_2 + CO_2e emissions (see Equation III.6d).

Equation III.6c	Convert Non-CO_2 GHGs to Carbon Dioxide Equivalent and Sum Total					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2					=	1,237.61 metric tons CO_2
CH_4 Tons of CO_2e	=	0.03347 metric tons CH_4	x	21 (GWP)	=	0.70287 metric tons CO_2e
N_2O Tons of CO_2e	=	0.01644 metric tons N_2O	x	310 (GWP)	=	5.0964 metric tons CO_2e
				Total	=	1,243.41 metric tons CO_2e

Equation III.6d	Total GHG Emissions from Electricity Use			
Total CO_2e Emissions (metric tons)	=	Total CO_2 Emissions (metric tons)	+	Total CO_2e Emissions (metric tons)

III.6.2 Alternate Methods to Estimate Electricity Use

Some organizations have difficulty reporting their indirect emissions from purchased electricity because their electricity use is not separately metered. As previously mentioned, these organizations must still calculate and report their estimated indirect emissions. To calculate their electricity use, such organizations have four options:

1. Estimate energy use based on a participant's share (percent of square footage) of the building in which they are using energy and the building's total annual electricity consumption.
2. Estimate energy use based on an energy audit.
3. For office space in California only, estimate energy use based on square footage and the average annual electricity intensity in your service territory.
4. Estimate energy use based on square footage and average electricity intensity of comparable facilities.

Reporters who cannot obtain actual electricity meter readings should clearly indicate, both to their verifier and in their public CARROT report, which methodology was used to estimate their indirect emissions from purchased electricity.

Methodology Disclosure

All members using an alternate estimation methodology must disclose publicly in CARROT that they are unable to obtain their electric bills and are estimating their emissions.

The California Registry asks that members use the following standard disclosure language in their public CARROT report:

"[Some or all] of the indirect emissions from purchased electricity disclosed in this report are estimated based on a California Registry-approved methodology for estimating electricity use, not calculated based on metered data."

Rentable Space vs. Usable Space

Depending on which of the alternate methodologies you use, you may be required to identify the square footage of your operations and the total square footage of your building. It is important to identify, through your lease and with your landlord, your usable square footage, not your rentable square footage.

Rentable square footage is the usable square footage plus the tenant's pro-rata share of the building common areas, such as the lobby, public corridors, and restrooms. Usable square footage is the area contained within the walls of the tenant space (i.e., the space you occupy).

Tenants of leased space typically do not have control over electricity usage or temperature in common space areas, hence it does not fall within your management control. Consequently, common space should not be included in your square footage calculations. You should only estimate the indirect emissions from purchased electricity for the usable square footage of the space that you occupy.

Method 1 – Leased Space

The following steps provide instructions on how to arrive at an estimate of energy use by determining your proportion of the building's total energy use.

Step 1: Determine your building's total annual electricity consumption.

Collect your building's monthly electricity bills and record the kilowatt-hours consumed each month. Then, add together the total kWh for the year.

If your electric bill does not begin or end exactly on January 1 and December 31, but spans two calendar years, you must pro-rate your electricity use to properly quantify the emissions for the calendar year being reported; refer to Equation III.6a.

Alternatively, if the building is unwilling to provide you with the electricity bills, you can request an attestation from the building owner/manager regarding the building's annual energy usage and usable square footage.

Step 2 Calculate your organization's share of total building electricity consumption.

Next, you must identify your organization's total usable square footage occupied and determine what percentage this is of the building's total usable square footage. Multiply this percentage by the building's total annual electricity consumption.

Step 3: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factor for your state or power pool.

Step 4: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors (SAR) from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Method 2 – Energy Audit

Companies that choose to estimate their electricity use through an energy audit should consult with the California Registry in order to receive approval for its methodology.

Method 3 – Office Space in California Only

Please note that this methodology is applicable for leased office space located within California only. If you are unable to obtain information about your building's total energy use, follow these steps to estimate your emissions based on your square footage.

Step 1: Determine your office space's usable square footage.

Review your lease, which should include your square footage information.

Step 2: Determine which electric utility services your building.

Contact your property management company to request the name of the provider. If you cannot obtain this information from your property management company, consult your local utility to confirm the electricity provider for your office.

Step 3: Determine the average annual electricity intensity in your service territory.

Average electricity intensity, broken out by small and large offices, is available for four of California's largest utilities. (Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and San Diego Gas & Electric (SDG&E)) from the California Energy Commission. These are summarized below:

	Annual Electricity Intensity (kWh/ft²)			
	PG&E	SCE	SDG&E	SMUD
Small Office (<30,000 ft²)	13.49	13.25	12.13	12.41
Large Office (>30,000 ft²)	16.77	17.91	19.23	19.95

Source: California End-Use Survey, California Energy Commission, March 2006. http://www.energy.ca.gov/ceus/index.html)

If your office location does not fall into one of these utility service areas, use the electricity intensity for the service area closest to your office location.

Step 4: Calculate your office's electricity consumption.

Equation III.6e	Estimated Annual Electricity Comsumption			
Usable Office Space (ft²)	x	Annual Electricity Intensity (kWh/ft²)	=	Your estimated annual electricity consumption (kWh)

Step 5: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factors that are available for your state or power pool.

Step 6: Determine total annual emissions and convert to metric tons.

Multiply your estimated electricity use in kilowatt-hours from Step 4 by the emission factors for CO_2, CH_4, and N_2O from Step 5. To convert pounds into metric tons, divide the total by 2,204.62 lbs/metric ton (see Equation III.6b).

Step 7: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors from Appendix C, Table C.1 (SAR) to convert CH_4 and N_2O to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Method 4 – Comparable Facilities

Where electricity records are not available and total annual electricity consumption of your operations is unknown, you can estimate electricity use based on the size of your space and function of the facility.

Use the following steps to estimate the electricity use at your operations:

Step 1: Determine your operations' usable square footage.

Review your lease, which should include your square footage information.

Step 2: Identify comparable facilities with known annual electricity use rates and usable square footage.

If possible, these facilities should be owned or operated by your organization. You should consider the primary function of the facility and the primary uses of electricity at each facility. You may also consider the age, hours of operation, number of occupants, and the type of heating and cooling systems employed in the buildings.

If electricity consumption for another comparable space owned or operated by your organization is not available, average energy intensity by principal building activity is available from the U.S. Energy Information Administration Commercial Building Energy Consumption Survey (CBECS). This information is summarized in Table III.6.1. In order to determine the appropriate principal building activity, consult CBECS' definitions at www.eia.doe.gov/emeu/cbecs/building_types.html.

Step 3: Determine electricity used per square foot at the comparable facility.

Divide the annual electricity use at the comparable facility by its usable square footage to obtain its annual electricity intensity (kWh/ft²).

Step 4: Calculate your office's electricity consumption.

Multiply the energy intensity metric calculated in Step 3 or the appropriate metric from Table III.6.1 by the usable square footage of the space for which you are estimating the electricity use (see Equation III.6e).

Step 5: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factors for your location.

Step 6: Determine total annual emissions and convert to metric tons.

Multiply your estimated electricity use from Step 4 by the emission factors for CO_2, CH_4, and N_2O you identified in Step 5. Then multiply the total by 2,204.62 lbs/metric ton (see Equation III.6b).

Step 7: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors from Appendix C, Table C.1 (SAR) to convert CH_4 and N_2O to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Table III.6.1 Annual Electricity Intensity Based On Principal Building Activity

Principal Building Activity	Annual Electricity Intensity (kWh/ft^2)
Education	11.0
Food Sales	49.4
Food Service	38.4
Health Care	22.9
Inpatient	27.5
Outpatient	16.1
Lodging	13.5
Retail (Other Than Mall)	14.3
Office	17.3
Public Assembly	12.5
Public Order and Safety	15.3
Religious Worship	4.9
Service	11.0
Warehouse and Storage	7.6
Other	22.5
Vacant	2.4

Source: Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey (CBECS): Consumption and Expenditures Tables, Table C14. Electricity Consumption and Expenditures Intensities for Non-Mall Buildings, 2003 (December 2006).

Optional Reporting:
Recognizing the Benefits of Green Power and Renewable Energy Certificates Purchases

The California Registry recommends participants use the following guidance to show how grid-related green power purchases and renewable energy credits (REC) impact indirect emissions estimates from electricity consumption. This information can be reported in the optional section of your annual emissions report, which will not be reviewed by your third-party verifier. The objective in providing guidance for optional reporting is to facilitate consistency and transparency in how renewable energy purchases are accounted for and reported in GHG inventories. The procedure below uses a line-item adjustment of your indirect emissions from electricity consumption to reflect the impact of your renewable energy purchases.*

Step 1: Distinguish and classify the type of renewable energy purchase.

Your renewable energy purchases will come either from your participation in a green power program (offered by an electric utility or an independent power provider), or from your direct purchase of RECs.

Step 2: Itemize total renewable energy purchases by type.

For each type of renewable energy purchase, determine the total kWh bought and record separately. The renewable power generated should occur within the same year as the scope of your report.

Step 3: Select the electricity emission factor(s) from Appendix C, Table C.2 that apply to the area in which the renewable power was generated.

If you bought renewable energy through a green power program, the California Registry recommends that you contact your green power program administrator for information on determining the geographic origin of renewable energy. REC purchases should have this information in the purchase agreement. The California Registry recommends that you determine the carbon dioxide impact as well as methane and nitrous oxide. Therefore, you should select an emission factor from Appendix C that corresponds to each gas.

Step 4: Multiply the total renewable energy purchase, by type, by the emission factor(s) selected in Step 3, convert non-CO_2 emissions to CO_2e, and sum the total.

Use the global warming potentials in Table C.1, Appendix C to convert non-CO_2 emissions to CO_2e. Add together the CO_2e emissions from the two types of purchases to determine total emissions.

Step 5: Subtract the total emissions from renewable energy purchases from the total indirect emissions from electricity consumption calculated in III.6.1 or III.6.2.

A line-item adjustment of your total indirect emissions from electricity consumption will show the positive impact associated with purchasing renewable energy through a green power program or from purchasing RECs.

You should disclose, to the maximum extent possible, the type of resource that generated the renewable power in the purchase agreement. EPA's Green Power Program provides additional information on what qualifies as an eligible or new renewable resource (see www.epa.gov/greenpower).

* The California Registry's recommended approach is consistent with EPA's current guidance for reporting purchases of green power and renewable energy certificates.

III.6.3 Example: Indirect Emissions from Electricity Use

Costlo Clothing Distributors

Costlo is a discount retail clothing chain with two outlets in Los Angeles, California, one in Portland, Oregon, and one in Tucson, Arizona. The company only purchases electricity and has no other GHG emissions.

Step 1: Determine annual electricity consumption.

Step 2: Select electricity emission factors that apply to the electricity purchased.

Because emission factors for electricity vary from region-to-region, Costlo tracks its electricity purchases by utility providing the electricity.

Annual Electricity Emissions and Emissions Factors

Region/ State	Power Generator	Annual Electricity Purchases (MWh)	CO_2 lbs/MWh	CH_4 lbs/MWh	N_2O lbs/MWh
CAMX/ California	Los Angeles	1,600	724.12	0.0302	0.0081
NWPP/Oregon	Portland	600	902.24	0.0191	0.0149
AZNM/Arizona	Tucson	800	1,311.05	0.0175	0.0179

Step 3: Determine total annual emissions and convert to metric tons.

Equation III.6b	Total Carbon Dioxide, Methane, and Nitrous Oxide Emissions for Electricity Use from Each Utility							
Los Angeles, CA	=	1,600 MWh	x	724.12 (lbs/MWh)	÷	2,204.62 lbs/mt	=	525.53 mt CO_2
Portland, OR	=	600 MWh	x	902.24 (lbs/MWh)	÷	2,204.62 lbs/mt	=	245.55 mt CO_2
Tucson, AZ	=	800 MWh	x	1,311.05 (lbs/MWh)	÷	2,204.62 lbs/mt	=	475.75 mt CO_2
						Subtotal	=	1,246.83 mt CO_2
Los Angeles, CA	=	1,600 MWh	x	0.0081 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00588 mt N_2O
Portland, OR	=	600 MWh	x	0.0149 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00406 mt N_2O
Tucson, AZ	=	800 MWh	x	0.0179 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00650 mt N_2O
						Subtotal	=	0.01644 mt N_2O
Los Angeles, CA	=	1,600 MWh	x	0.0302 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.02192 mt CH_4
Portland, OR	=	600 MWh	x	0.0191 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00520 mt CH_4
Tucson, AZ	=	800 MWh	x	0.0175 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00635 mt CH_4
						Subtotal	=	0.03347 mt CH_4

Step 4: Convert Non-CO_2 emissions to CO_2e and sum the total. Use Equation III.6c and III.6d.

Equation III.6c	Convert Non-CO_2 GHGs to Carbon Dioxide Equivalent and Sum Total					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2					=	1,246.83 metric tons CO_2
CH_4 Tons of CO_2e	=	0.03347 metric tons CH_4	x	21 (GWP)	=	0.70287 metric tons CO_2e
N_2O Tons of CO_2e	=	0.01644 metric tons N_2O	x	310 (GWP)	=	5.0964 metric tons CO_2e
				Total	=	1,252.63 metric tons CO_2e

Chapter 7 Direct Emissions from Mobile Combustion

Who should read Chapter 7:

Chapter 7 applies to all participants that operate motor vehicles or other forms of transportation.

What you will find in Chapter 7:

This chapter provides guidance on calculating your direct emissions from mobile combustion.

Information you will need:

You will need information about the types of vehicles your organization operates, where they are registered, fuel consumption, and miles traveled for each type of vehicle. Fuel consumption data may be obtained from bulk fuel purchases, fuel receipts or direct measurements of fuel use, such as official logs of vehicle fuel gauges or storage tanks. Sources of annual mileage data could include: odometer readings, trip manifests that include mileage to destinations, hours of operation or maintenance records.

Cross-References:

Be sure to complete Chapter 11 to determine any fugitive emissions you may have from motor vehicle air conditioning units, if applicable. Review Chapter 1 on geographic boundaries in considering which vehicles are based in California and which are not.

Mobile combustion sources are non-stationary emitters of GHGs such as automobiles, motorcycles, trucks, off-road vehicles such as forklifts and construction equipment, boats, and airplanes. On-road mobile sources include vehicles authorized by the California Department of Motor Vehicles to operate on public roads. Non-road mobile sources include, among other things, trains, ocean-going vessels, and commercial airplanes. Combustion devices that can be transported from one location to another (e.g., small diesel generators) are not considered mobile combustion sources. Reporters should refer to Section III.8 to calculate emissions from such equipment.

Emissions from mobile sources must be included in your emissions report, and can be calculated based on fuel use and/or vehicle miles traveled.

Carbon dioxide emissions, the primary GHG emissions from mobile sources, are directly related to the quantity of fuel consumed. Thus, emission factors are expressed in fuel quantity. On the other hand, combustion emissions of methane and nitrous oxide, while also related to fuel consumption, depend more on the emission control technologies employed in the vehicle. For this reason, their emission factors are typically expressed in terms of mass of compound emitted per distance traveled (gram/mile), and the method of calculating these emissions is based on mileage.

If you have your vehicles' annual fuel consumption information, you are ready to begin your CO_2 emissions calculations. If you have only information on your vehicle miles traveled, you will need to convert that data to fuel consumption based on U.S. EPA's mileage per gallon (mpg) estimates for your vehicles.[1]

The U.S. EPA provides estimates of on-road fuel consumption for passenger cars and light trucks. The California ARB also provides data on composite groups of passenger cars, heavy trucks, and motorcycles. For all other mobile sources, you will need to determine fuel consumption based either on your operating data or published information that is applicable to your vehicle application. EPA fuel economy figures are available at www.fueleconomy.gov/feg/. This website provides two figures for your calculation: one for city driving and one for highway driving.

III.7.1 Calculating Carbon Dioxide Emissions from Mobile Combustion

The method for estimating carbon dioxide emissions from mobile sources includes three steps:

1. Identify total annual fuel consumption by fuel type;
2. Select the appropriate CO_2 emission factor from Appendix C, Table C.3; and
3. Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert kilograms to metric tons.

If you have fuel consumption information, CARROT can calculate your CO_2 emissions for you.

Step 1: Identify total annual fuel consumption by fuel type.

If you are a fleet operator and store fuel at any of your facilities, you can also determine your annual fuel consumption from bulk fuel purchase records.

1 The guidance for calculating methane and nitrous oxide emissions from mobile combustion relies on equipment make, model, and miles driven.

Use Equation III.7a to help you determine your annual fuel consumption. The total annual fuel purchases should include both fuel purchased for the bulk fueling facility and fuel purchased for the vehicles at other fueling locations.

Equation III.7a	**Total Annual Fuel Consumption from Bulk Fuel Records**					
Total Annual Consumption	=	Total Annual Fuel Purchases	+	Amount Stored at Beginning of the Year	–	Amount Stored at End of Year

Besides bulk storage fuel purchases, additional sources of fuel consumption data may be obtained from collected fuel receipts (for non-bulk purchases) or direct measurements of fuel use, such as official logs of vehicle fuel gauges or storage tanks.

If you only have annual mileage information for the vehicles you own and operate, you may estimate your fuel consumption by using the following procedure or applying a default fuel economy factor.

1. Identify the vehicle make, model, fuel, and model years for all the vehicles you own and operate;
2. Identify the annual mileage by vehicle type; and
3. Convert annual mileage to fuel consumption using EPA's fuel economy formula (Equation III.7b).

If you have very accurate information about the driving patterns of your fleet, consider applying a more specific mix of city and highway driving, otherwise you may assume, as EPA does, that 45% of your vehicles' mileage is highway driving and 55% is city driving (see Equation III.7b). If you utilize more than one type of vehicle in your operations, you must calculate the fuel use for each of your vehicle types and sum them together.

Sources of annual mileage data could include odometer readings or trip manifests that include mileage to destinations. Vehicle mileage may be converted to fuel consumption using the EPA fuel economy of the specific vehicle models in the fleet (www.fueleconomy.gov). Carbon dioxide emissions are then calculated based on the fuel consumption.

For heavy-duty trucks for which no fuel efficiency information is available, you should assume fuel efficiency of 6 mpg for gasoline-powered trucks and 7 mpg for diesel-powered trucks.[2]

Equation III.7b	**Fuel Use in Motor Vehicles from Mileage Records**												
Total Fuel Use (gallons)	=	Total Mileage (miles)	÷	(	Fuel Economy City (mpg)	x	55%	+	Fuel Economy Highway (mpg)	x	45%	)	

Step 2: Select the appropriate carbon dioxide emission factor for each fuel from Appendix C, Table C.3 to calculate carbon dioxide emissions.

Appendix C, Table C.3 provides carbon dioxide emission factors for fuel combusted in motor vehicles and other forms of transport.

Step 3: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2 (see Equation III.7c) and convert kilograms to metric tons.

Equation III.7c	**Total CO_2 Emissions from Mobile Combustion**					
Total Emissions (metric tons)	=	Fuel Consumed (gallons)	x	Emission Factor (kg CO_2/gallon)	x	0.001 metric tons/kg

III.7.2 Calculating Methane and Nitrous Oxide Emissions for Mobile Combustion

The method for estimating emissions of methane and nitrous oxide from mobile sources involves six steps:

1. Identify the vehicle types, fuel, and model years of all the vehicles you own and operate;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle and fuel type (using Appendix C, Tables C.4 - C.6);
4. Calculate each vehicle type CH_4 and N_2O emissions and convert grams to metric tons;
5. Sum the emissions over each vehicle and fuel type; and
6. Convert CH_4 and N_2O Emissions to CO_2e and sum the subtotals.

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle types and fuel by model year are shown in Appendix C, Table C.4 for passenger cars, light trucks, and heavy-duty vehicles. The emission factors vary with model year because of changes in emission controls and catalysts. Emission factors for alternative fuel vehicles and non-highway vehicles, such as ships and aircraft, are shown in Appendix C, Tables C.5 and C.6.

2 U.S. Department of Energy, Transportation Energy DATA book edition 20 - 2000, Table 8.1.

Step 2: Identify the annual mileage by vehicle type.

If you do not have mileage but you do have fuel consumption by vehicle type model and year you can estimate the vehicle miles traveled using the EPA fuel economy of the specific vehicle models in the fleet. You can then calculate methane and nitrous oxide emissions based on vehicle miles traveled. If you have only bulk fuel purchase data, you should allocate consumption across vehicle types and model years in proportion to the fuel consumption distribution among vehicle type and model years, based on your usage data.

EPA fuel economy figures are available at www.fueleconomy.gov/feg/. Two figures are provided: one for city driving and one for highway driving. You may assume, as EPA does, that 45% of your vehicles' mileage is highway driving and 55% is city driving unless you have specific information to indicate otherwise (see Equation III.7d).

Equation III.7d	Vehicle Mileage from Fuel Use Records											
Total Mileage (mi.)	=	Fuel use (gallons)	x	(	Fuel Economy City (mpg)	x	55%	+	Fuel Economy Highway (mpg)	x	45%	)

Step 3: Select the appropriate emission factor for each vehicle and fuel type from Appendix C, Tables C.4, C.5, and C.6.

Step 4: Calculate each vehicle type CH_4 and N_2O emissions and convert to metric tons.

Use Equation III.7e to calculate total emissions for CH_4 and N_2O for each vehicle type.

Equation III.7e	Total CH_4 or N_20 Emissions from Mobile Combustion					
Total Emissions (metric tons)	=	Emission Factor by Vehicle and Fuel Type (g/mi)	x	Annual Mileage	x	0.000001 metric tons/g

Step 5: Sum the emissions for each vehicle and fuel type.

Add emissions for each vehicle and fuel combination to obtain the total emissions from all mobile sources.

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

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

Emissions from Alternative Fuel Vehicles:

Emissions from Alternative Fuel Vehicles (AFV) are calculated in the same manner as other gasoline or diesel mobile sources, except for electric vehicles. For instance, participants with compressed natural gas or propane fueled vehicles must, as in Section III.7.1, determine the total amount of fuel consumed and apply the appropriate emission factor to calculate emissions. Emission factors for AFVs are included in Appendix C, Table C.5.

Electric vehicles are powered by internal batteries that receive a charge from the electricity grid. Therefore, using electric vehicles produces indirect emissions from purchased electricity.

III.7.3 Calculating Emissions from Off-Road Vehicles/ Construction Equipment

To calculate CO_2 emissions from off-road vehicles/ construction equipment, you should use fuel consumption data and the calculation methodology provided in Section III.7.1 for on-road vehicles.

To calculate the emissions of non-CO_2 gases (e.g., CH_4 and N_2O) from off-road vehicles/construction equipment, you should use fuel consumption data and the off-road vehicle/ construction equipment emission factors in Appendix C, Table C.6. These fuel use-based emission factors are more appropriate than the distance-based emission factors used to calculate emissions of non-CO_2 gases from other mobile sources because off-road vehicles/construction equipment do not have the emission control technologies required of on-road vehicles and, in many instances, do not record miles traveled.

If any off-road equipment has been permitted by a local air regulatory authority as a stationary source, its emissions should be included as stationary combustion, not mobile combustion.

III.7.4 Calculating Carbon Dioxide Emissions from Biofuels

The emissions from vehicles that use biofuels need to be calculated differently than vehicles that use petroleum-based fuels. Biofuels are fuels that are derived from vegetable oil or animal fats that can be added to petroleum -based gasoline or diesel as a blend or used on their own. Since biofuels are derived from a non-petroleum source, the CO_2 emissions that result from their combustion are considered to be biogenic emissions. International consensus on the net climate impact from the combustion of biofuels has not yet been reached. Due to the distinction between biogenic and anthropogenic emissions, the emissions associated with the biofuel portions of biodiesel and ethanol should not be included as a direct mobile emission in your inventory. However, you may choose to report these emissions optionally.

Please note that CH_4 and N_2O emissions from the combustion of biofuels are considered anthropogenic and should be calculated and reported as part of your emissions inventory. CH_4 and N_2O emission factors for biofuels can be found in Appendix C, Table C.5.

Biodiesel is available in both its pure form (100% biodiesel, also known as B100) and in blends with petroleum diesel. Ethanol is generally found as E85, where the fuel is composed of 85% ethanol and 15% gasoline. If your organization is using a blended fuel, you need to include emissions from the petroleum portion of the fuel in the direct mobile emissions section of your inventory. Follow the steps below to calculate the anthropogenic and biogenic CO_2 emissions from a biofuel blend.

Step 1: Identify the biofuel blend being used.

The most popular biodiesel blends are B5 (5% biodiesel), B20 (20% biodiesel) and B100, but any blend between B1 to B100 is possible. Ethanol is most commonly found as E85, but can also occur in a pure form (E100) and in other blends such as E5, E10, E25, etc.

Step 2: Identify total annual biofuel consumption.

Calculate consumption from fuel purchase receipts and/or from vehicle miles traveled. If you are a fleet operator and store fuel at any of your facilities, you can also determine your annual fuel consumption from bulk fuel purchase records.

Step 3: Based on the blend, calculate the annual consumption of petroleum-based fuel and biofuel.

For example, if you are using B20, your annual consumption would have to be split into 20% biodiesel and 80% diesel fuel. For this calculation, see Example III.7.6.

Step 4: Select the appropriate emission factor to calculate the anthropogenic CO_2 emissions.

Appendix C, Table C.3 provides CO_2 emission factors for fuel combusted in motor vehicles and other forms of transport. The CO_2 emission factor for diesel is 10.15 kg per gallon and is 8.81 kg per gallon of gasoline.

Step 5: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Multiply your petroleum-based fuel use from Step 3 by the CO_2 emission factor from Step 4 (See Equation III.7c) and convert kilograms to metric tons.

To calculate the CH_4 and N_2O emissions from ethanol and biodiesel, follow the guidance given in Section III.7.2 and use the emission factors as specified in Appendix C.

Optional Reporting of Biogenic Emissions

If you want to report the biogenic CO_2 mobile emissions from your biofuel use in the optional section of your report, use the same methodology in Steps 4 and 5 above, but use the biofuel CO_2 emission factors for the biofuel portions of your annual fuel use. See Example III.7.6 for how biogenic CO_2 emissions would be calculated for a biodiesel blend. Ethanol-attributed CO_2 emissions would be calculated in the same fashion.

III.7.5 Example: Direct Emissions from Mobile Combustion

GOFAST Vehicle Rental Agency

GOFAST Vehicle Rental is an independent vehicle renting company with a fleet of 200 model year 2000 passenger cars, 25 model year 2000 light duty trucks, and two model year 1998 heavy duty diesel powered trucks. GOFAST typically purchases its fuel in bulk. Last year, the company purchased 235,000 gallons of motor gasoline and 5,000 gallons of diesel fuel. GOFAST began the year with 20,000 gallons of motor gasoline in stock and ended with 10,000 gallons of motor gasoline in stock. The company also began the year with 500 gallons of diesel fuel in stock and ended with 1,000 gallons of diesel fuel in stock.

Carbon Dioxide Emissions Calculation

Step 1: Identify the total annual fuel consumption by fuel type.

Equation III.7a	Total Annual Fuel Consumption by Fuel Type							
Total Fuel Consumption	=	Total Annual Fuel Purchases	+	Amount Stored at Beginning of the Year	-	Amount Stored at End of Year		
Total Gasoline Consumption	=	235,000 gallons	+	20,000 gallons	-	10,000 gallons	=	245,000 gallons
Total Diesel Consumption	=	5,000 gallons	+	500 gallons	-	1,000 gallons		4,500 gallons

Step 2: Select the appropriate carbon dioxide emission factor for each fuel from Appendix C, Table C.3 to calculate carbon dioxide emissions.

The CO_2 emission factor for motor gasoline is 8.81 kilograms per gallon and for diesel fuel it is 10.15 kilograms per gallon.

Carbon Dioxide Emission Factors for Transport Fuels

Carbon Dioxide Emission Factor		
Fuel	**kg CO_2/MMBtu**	**kg CO_2/gal**
Gasoline	NA	8.81
Diesel Fuel	NA	10.15

Step 3: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions.

Equation III.7c	Carbon Dioxide Emissions Contribution of Each Fuel							
CO_2 from Motor Gasoline	=	8.81 kg/gallon	x	245,000 gallons	x	0.001 metric tons/kg	=	2,158.45 metric tons CO_2
CO_2 from Diesel Fuel	=	10.15 kg/gallon	x	4,500 gallons	x	0.001 metric tons/kg	=	45.68 metric tons CO_2
						Total	=	2,204.13 metric tons CO_2

Methane and Nitrous Oxide Emissions Calculation

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle Type, Fuel, and Model Year

Vehicle Type	Fuel	Model Year
Passenger Cars	Motor Gasoline	1998 through 2002
Light Duty Trucks	Motor Gasoline	1998 through 2002
Heavy Duty Trucks	Diesel	1998

Step 2: Identify the annual mileage by vehicle type

First, GOFAST will have to allocate gross fuel consumption (gallons consumed per year) by vehicle type and model year. For the purposes of this example, it is assumed that GOFAST is able to calculate total fuel consumption based on fuel purchase receipts to arrive at total gallons of fuel consumed for each vehicle type

Then GOFAST must determine vehicle miles traveled using EPA mpg estimates, using Equation III.7d.

Gross Fuel Consumption by Vehicle Type

Vehicle Type	Fuel	Model Year	Fuel Consumption
Passenger Cars	Motor Gasoline	2000	225,000 gallons
Light Duty Trucks	Motor Gasoline	2000	20,000 gallons
Heavy Duty Trucks	Diesel	1998	4,500 gallons

Equation III.7b	Annual Vehicle Miles Traveled												
Total Mileage (mi.)	=	Fuel use (gallons)	x	(	Fuel Economy City (mpg)	x	55%	+	Fuel Economy Highway (mpg)	x	45%	)	
Total Mileage –passenger (mi.)	=	225,000 gallons	x	(	20 mpg	x	55%	+	25 mpg	x	45%	)	= 5,006,250 miles
Total Mileage – light duty (mi.)	=	20,000 gallons	x	(	15 mpg	x	55%	+	20 mpg	x	45%	)	= 345,000 miles
Total Mileage – heavy duty (mi.)	=	4,500 gallons	x	(	8 mpg	x	55%	+	10 mpg	x	45%	)	= 40,050 miles

Step 3: Select the appropriate emission factor from Appendix C, Table C.4 for each vehicle and fuel type.

Emission Factors for Each Fuel and Vehicle Type

Vehicle Type	Fuel	Model Year	Methane (g/mi)	Nitrous Oxide (g/mi)
Passenger Cars	Motor Gasoline	2000	0.0178	0.0273
Light Duty Trucks	Motor Gasoline	2000	0.0346	0.0621
Heavy Duty Trucks	Diesel	1998	0.0051	0.0048

Step 4: Calculate each vehicle type CH_4 and N_2O emissions and convert to metric tons.

Equation III.7e	Passenger Cars: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0178 g/mi	x	5,006,250 (mi)	x	0.000001 metric tons/g	=	0.0891 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0273 g/mi	x	5,006,250 (mi)	x	0.000001 metric tons/g	=	0.1367 metric tons N_2O

Equation III.7e	Light Duty Trucks: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0346 g/mi	x	345,000 (mi)	x	0.000001 metric tons/g	=	0.0119 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0621 g/mi	x	345,000 (mi)	x	0.000001 metric tons/g	=	0.0214 metric tons N_2O

Equation III.7e	Heavy Duty Trucks: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0051 g/mi	x	40,050 (mi)	x	0.000001 metric tons/g	=	0.0002 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0048 g/mi	x	40,050 (mi)	x	0.000001 metric tons/g	=	0.0002 metric tons N_2O

Step 5: Sum the methane and nitrous oxide emissions for each vehicle and fuel type.

Total Emissions from Mobile Combustion

Vehicle Type	Fuel	Model Year	CH_4 (metric tons)	N_2O (metric tons)
Passenger Cars	Motor Gasoline	2000	0.0891	0.1367
Light Duty Trucks	Motor Gasoline	2000	0.0119	0.0214
Heavy Duty Trucks	Diesel	1998	0.0002	0.0002
		Total	0.1012	0.1583

Step 6: Convert CH_4 and N_2O emissions to CO_2e and sum the subtotals using the GWPs in Appendix C, Table C.1.

Equation III.6c	Convert to Carbon Dioxide Equivalent					
	=	Total Emissions (metric tons)	x	GWP factor		
Total CO_2e (metric tons)	=	0.1012 metric tons CH_4	x	21 (GWP)	=	2.13 metric tons CO_2e
	=	0.1583 metric tons N_2O	x	310 (GWP)	=	49.07 metric tons CO_2e

Total CO_2e Emissions from Mobile Combustion

GHG	metric tons CO_2e
CO_2	2,204.13
CH_4	2.13
N_2O	49.07
Total	2,255.33 metric tons CO_2e

III.7.6 Example: Carbon Dioxide Emissions from Biodiesel

BioClean Drycleaning Service

BioClean is an environmentally-friendly dry cleaning service with a delivery fleet of 10 biodiesel vans. Last year, the company purchased 12,000 gallons of B20 to fuel their vans.

Step 1: Identify the biodiesel blend being used.

BioClean is using B20, which is made up of 20% biodiesel and 80% petroleum-based diesel.

Step 2: Identify total annual biodiesel consumption.

BioClean purchased 12,000 gallons of B20 – they do not store fuel on-site, so no additional mass balance calculation is needed.

Step 3: Based on the blend, calculate the annual consumption of diesel and biodiesel.

Annual consumption of B20 = 12,000 gallons

12,000 gallons x 80% = 9,600 gallons diesel consumed

12,000 gallons x 20% = 2,400 gallons biodiesel consumed

Step 4: Select the appropriate emission factor for the petroleum-based diesel from Appendix C, Table C.3 to calculate the anthropogenic CO_2 emissions.

The CO_2 emission factor for diesel is 10.15 kilograms per gallon, and the biogenic CO_2 emission factor for biodiesel is 9.46 kilograms per gallon.

Carbon Dioxide Emission Factors for Transport Fuels

Fuel	kg CO_2/gallon
Diesel	10.15
Biodiesel (B100)	9.46*

* Note that the CO_2 emissions from burning biodiesel are biogenic, and should not be included as direct mobile emissions in your inventory. These emissions may be reported optionally.

Step 5: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Equation III.7c	CO_2 Emissions Contribution of Each Fuel							
CO_2 from diesel	=	10.15 kg/ gallon	x	9,600 gallons	x	0.001 metric tons/kg	=	97.44 metric tons CO_2
Biogenic CO_2 from biodiesel	=	9.46 kg/ gallon	x	2,400 gallons	x	0.001 metric tons/kg	=	22.70 metric tons biogenic CO_2

Chapter 8 Direct Emissions from Stationary Combustion

Who should read Chapter 8:

Chapter 8 applies to participants who generate energy on-site.

What you will find in Chapter 8:

This chapter provides guidance on determining direct emissions from stationary combustion from activities like power generation, manufacturing or other industrial activities involving the combustion of fossil fuels.

Information you will need:

You will need information about the type of fuels consumed by your organization and how much was combusted in the reporting year, or CEMS data.

Cross-References:

If your organization imports steam or district heating and cooling, you will utilize the calculation guidelines in Chapter 9 to assist you in calculating these indirect emissions.

Stationary combustion sources are non-mobile sources emitting GHGs from fuel combustion. Typical large stationary sources include power plants, refineries, and manufacturing facilities. Smaller stationary sources include commercial and residential furnaces.

If you combust fuels to produce electricity for your own use or make steam or district heating and cooling for your own use or to sell, then it should also follow the GHG emissions accounting and reporting guidelines in this chapter. However, if you combust fossil fuels to produce electricity and sell the power to other parties (an electric power generator) then you should use the California Registry's Power/Utility Protocol.

III.8.1 Emission Factors for Stationary Combustion

Default emission factors are provided in Appendix C, Tables C.7, C.8, and C.9. If your company has verifiable emission factors that are more accurate for the fuels and combustion devices that your organization employs, you may use these factors. If you decide not to use the California Registry-approved emission factors, you will need to demonstrate to your verifier that the use of the alternative emission factors results in a more accurate measurement of your emissions.

The following is a list of sources where you can obtain additional emission factors:

- U.S. EPA, Compilation of Air Pollutant Emission Factors AP-42, www.epa.gov/ttn/chief/ap42;
- U.S. EPA Emissions Inventory Improvement Program (EIIP) Introduction to Estimating Greenhouse Gas Emissions: Volume VII (EIIP, 1999), www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html;
- 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Greenhouse Gas Inventories Reference Manual (IPCC, 2006), www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm; and
- UK Department for Environment, Food, and Rural Affairs, Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme (DEFRA, 2004), www.defra.gov.uk/environment/climatechange/trading/uk/documents.htm.

III.8.2 Estimating Emissions Based on Higher Heating Value

To estimate stationary combustion emissions, the Protocol utilizes GHG emission factors that are based on the "higher" heating value (HHV) (or "gross" heating value (GHV)) for combusted fossil fuels. When hydrocarbons are combusted, heat, water vapor, and CO_2 are emitted, along with trace levels of other GHGs like CH_4 and N_2O. In the United States, a HHV is used to measure the heat content of fuels and is therefore used to estimate GHG emissions from the combustion process. This approach is used by the U.S. Energy Information Administration (EIA). However, it should be noted that the "lower" heating value (LHV) is typically used internationally.[1]

III.8.3 Using Continuous Emissions Monitoring System Data

Typically, participants calculate GHG emissions from stationary combustion using the process outlined in the subsequent section. However, if you use a Continuous Emissions Monitoring System (CEMS) to measure emissions, you may also report your stationary combustion emissions from your CEMS reports.

1 Converting from HHVs to LHVs is an imperfect process. Emissions estimates based on LHVs are between 5% to 10% higher because the Btu content of the fuel is around 5% to 10% lower. See OECD, Estimation of Greenhouse Gas Emissions and Sinks, Final Report (Paris, France, August 1991), pp. 2-12 – 2-15.

Participants using CEMS should refer to the California Registry's Power/Utility Protocol for guidance on reporting emissions from combustion devices equipped with CEMS units.

Stationary Emissions from Agriculture Residue Burning:

This Protocol does not include specific guidance on estimating emissions from agricultural residue burning. Useful information is provided in the CEC's Guidance to the California Climate Action Registry: General Reporting Protocol, P500-02-005F (June 2002).

III.8.4 Calculating Emissions from Stationary Combustion

Emissions estimation for stationary combustion involves the following process:

1. Identify all types of fuel directly combusted in your operations;
2. Identify annual consumption of each fuel;
3. Select the appropriate adjusted 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 and convert to metric tons; and
6. Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

CARROT can also calculate this information for you, and will prompt you to enter your fuel type and inputs.

Step 1: Identify all types of fuel directly combusted in your operations.

Fuel types can include, for example, coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Step 2: Determine annual consumption of each fuel.

This can be done by direct measurement, recording fuel purchase, or sales invoices measuring any stock change (measured in million Btu, gallons or therms) using Equation III.8a.

Equation III.8a	Annual Consumption of Fuels							
Annual Consumption (MMBtu or gallons)	=	Total Annual Fuel Purchases	-	Total Annual Fuel Sales	+	Amount Stored at Beginning of Year	-	Amount Stored at Year End

If your fuel consumption is not available in million Btu, gallons or therms, you can convert it using the conversion factors in Table III.8.1.

Table III.8.1 Conversion Factors for Stationary Combustion Calculations

Unit	Multiplied by	Equals
Barrels	42.0	1 Gallon
Therms of Natural Gas	0.1	Million Btu
Thousand Cubic Feet of Natural Gas	1.03	Million Btu
Metric Tons of Coal, Electric Utility	22.488	Million Btu
Metric Tons of Coal, Industrial Coke	30.232	Million Btu
Metric Tons of Coal, Other Industry	24.790	Million Btu
Metric Tons of Coal, Residential & Commercial	26.323	Million Btu

Source: Energy Information Administration, Annual Energy Review 2000 (2002).

Step 3: Select the appropriate emission factor for each fuel.

Each fuel type has a specific emission factor that relates to the amount of CO_2, CH_4 or N_2O emitted per unit of fuel consumed (either in kilograms per MMBtu of fuel or kilograms per gallon of fuel). CO_2 emission factors depend almost completely on the carbon content of the fuel. CH_4 and N_2O emission factors also depend on the type of combustion device and the combustion conditions.

Carbon Dioxide. Appendix C, Table C.7 provides CO_2 emission factors for the most common fuel types in kilograms of CO_2 per million Btu (MMBtu) and in kilograms of CO_2 per gallon for liquid fuels. If you burn a fuel that is not listed in Appendix C, Table C.7, you should estimate an emission factor based on the specific properties of the fuel and document those properties.

Methane and Nitrous Oxide. Appendix C, Tables C.8 and C.9 present CH_4 and N_2O emission factors by activity sector and fuel type. For petroleum products, emission factors for CH_4 and N_2O are provided in kilograms per MMBtu and kilograms per gallon consumed.

Step 4: Calculate each fuel's carbon dioxide emissions and convert to metric tons.

If the fuel consumption is expressed in MMBtu, use Equation III.8b. If fuel is expressed in gallons, use Equation III.8c.

Equation III.8b	Total CO_2 Emissions (fuel consumption is in MMBtu)					
Total Emissions (metric tons)	=	Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation III.8c	Total CO_2 Emissions (fuel consumption is in gallons)					
Total Emissions (metric tons)	=	Emission Factor (kg CO_2/gallon)	x	Fuel Consumed (gallon)	x	0.001 metric tons/kg

Step 5: If you are reporting methane and nitrous oxide emissions, calculate each fuel's methane and nitrous oxide emissions and convert to metric tons.

If your fuel consumption is expressed in MMBtu, use Equation III.8d. If it is expressed in gallons, use Equation III.8e. Note, non-CO_2 gases may be de minimis.

Equation III.8d	Total CH_4 or N_2O Emissions (fuel consumption is in MMBtu)					
Total Emissions (metric tons)	=	Emission Factor (kg CH_4 or N_2O / MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/ kg

Equation III.8e	Total CH_4 or N_2O Emissions (fuel consumption is in gallons)					
Total Emissions (metric tons)	=	Emission Factor (kg CH_4 or N_2O / gallon)	x	Fuel Consumed (gallon)	x	0.001 metric tons/ kg

Step 6: Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert CH_4 and N_2O to CO_2 equivalent.

III.8.5 Allocating Emissions from Co-Generation

Accounting for the GHG emissions from a co-generation or combined heat and power (CHP) facility is unique 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 useful.[2]

Ultimately, to comply with California Registry reporting guidelines, reporters only have to determine absolute emissions from a co-gen plant. This is done in a manner identical with the calculation procedure for non-co-generation plants. That is, to calculate total emissions associated with a co-generation plant participants multiply the fuel input by a fuel specific emission factor. Alternatively participants can allocate emissions according to each final product stream (i.e., electricity or steam). 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 products.

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 is 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

2 Many CHP systems capture the waste-heat from the primary electricity generating pathway and use it for non-electricity purposes. 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.)

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 ensure a consistent approach in 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 GHG Protocol.[3]

Using the Efficiency Method to Allocate Emissions from CHP Facilities

For this method, emissions are allocated based on the separate efficiencies of steam and electricity production. You will need to know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of CO_2 emissions attributable to steam (or heat) and electricity production:

Step 1: Determine the total direct emissions from the CHP system.

Calculate total direct GHG emissions using Equation III.8b or III.8c, above. Like the guidance for non-cogeneration stationary combustion, calculating total emissions from CHP sources is based on fuel input values.

Step 2: Determine the total steam and electricity output for the CHP system.

To determine the total energy output of the CHP plant attributable to steam production, use published steam tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions. Obtain steam energy content values from the IAPWS-IF97 steam tables.[4] Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values; express in units of MMBtu.

Alternatively, use Equation III.9a to determine the total net heat steam (or heat) production.

To convert total electricity production from MWh to MMBtu, multiply by 3.415.[5]

3 GHG Protocol, 2004 .

Step 3: Determine the efficiencies of steam and electricity production.

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80% for steam and a default value of 35% for electricity.[6]

Step 4: Determine the fraction of total emissions to allocate to steam and electricity production.

Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation III.8f.

Where:

E_H = Emissions allocated to steam production

H = Total steam (or heat) output (MMBtu)

e_H = Efficiency of steam (or heat) production

P = Total electricity output (MMBtu)

e_P = Efficiency of electricity generation

E_T = Total direct emissions of the CHP system

E_P = Emissions allocated to electricity production

Equation III.8f — Steam and Electricity Emissions Allocation

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

$$\text{and} \quad E_P = E_T - E_H$$

4 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 IFC-67.

5 MWh to MMBtu conversion source – EIA, Annual Energy Review 1995, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

6 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. If the constraints are not satisfied the efficiencies of the steam and electricity can be modified until constraints are met.

III.8.6 Example: Direct Emissions from Stationary Combustion

F&M Manufacturing

F&M is a manufacturing facility located in California. It has two 10 MW generating units, one burning natural gas and one coal-fired unit. F&M also has a commercial office building in California that is heated with diesel.

Step 1: Identify all types of fuel directly combusted in your operations.

Fuel Type, Sector, and Location

Fuel	Sector
Natural Gas	Manufacturing
Coal	Manufacturing
Diesel	Commercial

Step 2: Determine annual consumption of each fuel.

F&M measures heat input (MMBtu of fuel used) into its plants, and purchases its heating fuel for commercial use in bulk by the barrel. Last year it consumed 788,400 MMBtu of natural gas and 946,000 MMBtu of coal. It also purchased 265 barrels of distillate fuel for heating and sold 15 barrels. F&M began the year with 12 barrels in storage and ended the year with 24 barrels in storage. Using Equation III.8a, F&M determined distillate fuel consumption. The result, 238 barrels can be converted to gallons by multiplying by 42. See Table III.8.1.

Equation III.8a	Annual Consumption of Fuels									
Annual Consumption (MMBtu or gallons)	=	Total Annual Fuel Purchases	-	Total Annual Fuel Sales	+	Amount Stored at Beginning of Year	-	Amount Stored at Year End		
Annual Consumption of Distillate Fuel	=	265 barrels	-	15 barrels	+	12 barrels	-	24 barrels	=	238 barrels consumed
						238 barrels consumed	x	42 gallons/ barrel	=	9,996 gallons

Step 3: Select the appropriate emission factors for each fuel from Appendix C, Tables C.7, C.8 and C.9.

Emission Factors by Fuel Type and Sector

		kg CO_2 per		kg CH_4 per		kg N_2O per	
Fuel	**Sector**	**MMBtu**	**Gallon**	**MMBtu**	**Gallon**	**MMBtu**	**Gallon**
Natural Gas	Manufacturing	53.06	–	0.0010	–	0.0001	–
Coal	Manufacturing	93.98	–	0.0110	–	0.0016	–
Distillate Fuel/Diesel	Commercial	73.15	10.15	0.0110	0.0015	0.0006	0.0001

Step 4: Calculate each fuel's carbon dioxide emissions.

Use Equation III.8b if the fuel consumption is expressed in MMBtu, and Equation III.8c if it is expressed in gallons.

Equation III.8b	Carbon Dioxide Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	53.06 kg CO_2/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	41,832.5 metric tons CO_2

Equation III.8b	Carbon Dioxide Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	93.98 kg CO_2/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	88,905.08 metric tons CO_2

Equation III.8c	Carbon Dioxide Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	10.15 kg CO_2/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	101.46 metric tons CO_2

Total CO_2 from All Sources	=	130,839.04 metric tons CO_2

Step 5: Calculate each fuel's methane and nitrous oxide emissions.

Use Equation III.8d if the fuel consumption is expressed in MMBtu, and Equation III.8e if it is expressed in gallons. Note, both methane and nitrous oxide emissions from stationary combustion are likely to be de minimis.

Equation III.8d	Methane Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	0.0010 kg CH_4/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	0.788 metric tons CH_4

Equation III.8d	Methane Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	0.0110 kg CH_4/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	10.406 metric tons CH_4

Equation III.8e	Methane Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	0.0015 kg CH_4/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	0.015 metric tons CH_4

Total CH_4 from All Sources	=	11.21 metric tons CH_4

Equation III.8d	Nitrous Oxide Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	0.0001 kg N_2O/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	0.0788 metric tons N_2O

Equation III.8d	Nitrous Oxide Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	0.0016 kg N_2O/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	1.514 metric tons N_2O

Equation III.8e	Nitrous Oxide Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	0.0001 kg N_2O/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	0.0010 metric tons N_2O

Total N_2O from All Sources	=	1.594 metric tons N_2O

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

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert CH_4 and N_2O to CO_2 equivalent.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)	=	130,839.04 metric tons CO_2e
CH_4 Tons of CO_2e	=	11.21 metric tons CH_4	x	21 (GWP)	=	235.41 metric tons CO_2e
N_2O Tons of CO_2e	=	1.594 metric tons N_2O	x	310 (GWP)	=	494.2 metric tons CO_2e
				Total	=	131,568.65 metric tons CO_2e

Chapter 9 Indirect Emissions from Imported Steam, District Heating and Cooling, and Electricity from a Co-Generation Plant

Who should read Chapter 9:

Chapter 9 applies to organizations that purchase electricity, steam or heating and cooling from a co-generation plant or conventional boiler that they do not own or operate.

What you will find in Chapter 9:

This chapter provides guidance on estimating indirect emissions from co-generation, imported steam, and district heating and cooling. The chapter includes the quantification methodology for co-generation and an example addressing indirect emissions from district heating.

Information you will need:

You will need information about the type of co-generation, imported steam and heat, and imported cooling your organization uses, and the types and amounts of fuel consumed by the plant to generate that electricity, heating or cooling. For example, for heat or electricity from a co-generation facility, you will need information about the plant's net heat production and net electricity production in addition to your organization's own consumption of that power.

This chapter applies to organizations that purchase steam, district heat, cooling or electricity from a co-generation or conventional boiler plant that they do not own or operate. Emissions associated with these sources are considered to be indirect. If you own or operate a co-generation or conventional boiler plant, you should calculate your direct emissions from the combustion of the fossil fuels at the plant as described in Chapter 8.

III.9.1 Calculating Indirect Emissions from Heat and Power Produced at a Co-Generation Facility

Emissions from co-generation facilities—also referred to as combined heat and power (CHP) plants—represent a special case for estimating indirect emissions. Because co-generation simultaneously produces electricity and heat (or steam), attributing total GHG emissions to each product stream would result in double counting. Thus, when two or more different parties receive the energy streams from co-generation plants, GHG emissions must be determined and allocated separately for heat production and electricity production. Since the output from co-generation results simultaneously in heat and electricity, you can determine what "share" of the total emissions is a result of electricity and heat by using a ratio based on the Btu content of heat and/or electricity relative to the co-generation plant's total output.

The process for estimating indirect emissions from heat and power produced at a co-generation facility involves the following five steps:

1. Obtain total emissions and power and heat generation information from co-generation facility;
2. Determine emissions attributable to net heat production and electricity production;
3. Calculate emissions attributable to your portion of heat and electricity consumed;
4. Convert any non-CO_2 emissions to carbon dioxide equivalent, as applicable; and
5. Sum CO_2e.

Step 1: Obtain emissions and power and heat information from the co-generation facility.

You will need to obtain the following information from the CHP plant owner or operator to estimate indirect GHG emissions:

1. Total emissions of carbon dioxide (and methane and nitrous oxide when they are being reported) from the co-generation facility - based on fuel input information;
2. Total electricity production from the co-generation plant - based on generation meter readings; and
3. Net heat production from the co-generation plant.

Net heat production refers to the useful heat that is produced in co-generation, minus whatever heat returns to the boiler as steam condensate, as shown in Equation III.9a.[1]

Equation III.9a	Net Heat Production			
Net Heat Production (MMBtu)	=	Heat of Steam Export (MMBtu)	-	Heat of Return Condensate (MMBtu)

Step 2: Determine emissions attributable to net heat production and electricity production for the co-generation plant.

Refer to Section III.8.5 in the Stationary Combustion chapter titled "Allocating Emissions from Co-Generation"

1 Alternatively, refer to p. 45 "Step 2" for guidance on determining net heat production from steam temperature and pressure data.

to calculate emissions attributable to net heat and electricity production.

Step 3: Calculate emissions attributable to your portion of heat and electricity consumed.

Once you have determined total emissions attributable to heat (or steam) and electricity production, you will need to determine your portion of heat or electricity consumed, and thus your indirect GHG emissions associated with heat or electricity use. First, obtain your electricity and heat (or steam) consumption information, then use Equations III.9b and III.9c to calculate your share of emissions, as appropriate.

Equation III.9b — Indirect Emissions Attributable to Electricity Consumption

$$\text{Indirect Emissions Attributable to Electricity Consumption} = \text{CHP Emissions Attributable to Electricity Production (metric tons)} \times \left(\text{Your Electricity Consumption (kWh)} \div \text{Total CHP Electricity Production (kWh)} \right)$$

Equation III.9c — Indirect Emissions Attributable to Heat or Steam Consumption

$$\text{Indirect Emissions Attributable to Heat Consumption (metric tons)} = \text{CHP Emissions Attributable to Heat Production (metric tons)} \times \left(\text{Your Heat Consumption (MMBtu)} \div \text{CHP Net Heat Production (MMBtu)} \right)$$

Step 4: Convert any non-CO_2 emissions to CO_2e, as applicable, and sum subtotals.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

III.9.2 Calculating Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

The following process leads participants through a procedure to calculate emissions from imported steam or district heating produced at a conventional boiler plant that does not generate electricity – i.e., the boiler plant is not a co-generation facility. The method for quantifying indirect emissions from imported steam or district heating largely mirrors that for calculating direct emissions from stationary combustion, with the additional step to incorporate efficiency losses for steam generation and distribution.

In order to calculate fuel consumption at the boiler, you can use the heat contained in the steam or hot water you receive, rather than rely on actual fuel measurements, which may not be available (see Equations III.9d and III.9e). Once you have identified fuel consumption at the boiler, you can calculate total emissions by multiplying total energy by the emission factors provided in Appendix C, Tables C.7, C.8, and C.9. If you know the efficiency factor for generation and transmission of imported steam or hot water, please use it in your calculation. (Note that heat loss during transmission should be reflected in this efficiency factor.)

If the efficiency is unknown, use an efficiency factor of 75%.

Use the following four steps to estimate your total GHG emissions from imported steam or district heating:

1. Determine energy obtained from steam or district heating;
2. Determine energy consumed at the steam or district heating plant;
3. Determine appropriate emission factor for the fuel; and
4. Multiply energy consumed by the emissions factor to derive emission estimates.

Step 1: Determine energy obtained from steam or district heating.

You can use monthly energy bills to determine the energy obtained from steam or district heating. The monthly bills should be summed together over the year to give annual consumption. You will want to total your data in million Btu (MMBtu).

Heating Bills Expressed in Therms. If your heating bills are expressed in therms, you can convert the values to MMBtu by multiplying by 0.1, as shown in the Equation III.9d.

Equation III.9d — Steam Energy Consumption (from therms)

$$\text{Energy Consumption (MMBtu)} = \text{Energy Consumption (therms)} \times 0.1 \text{ MMBtu/ therm}$$

Heating Bills Expressed in Pounds of Steam. If your steam consumption is billed in pounds (lbs), you either need to monitor the temperature and pressure of the steam you have received, or request it from the steam supplier. Calculate the thermal energy of the steam using saturated water at 212°F as the reference.[2] The thermal energy consumption is calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy (or heat content) of the saturated water at the reference conditions (or heat content). The enthalpy of the

2 American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry (2001).

3 See, for example, J.H. Keenan, Keyes, Hill, et al, Steam Tables (1969) and R.J. Reed, Ed., North American Combustion Handbook, Second Edition (1978), pages 349.

Equation III.9e — Steam Energy Consumption (from pounds)

$$\text{Energy Consumption (MMBtu)} = \left(\text{Enthalpy of Delivered Steam (Btu/lb)} - 180\ \text{(Btu/lb)} \times\right) \text{Mass of Steam Consumed (lbs)} \div 1{,}000{,}000\ \text{(Btu/MMBtu)}$$

Equation III.9f — Energy Input by Steam or District Heating Plant

$$\text{Energy Consumption (MMBtu)} = \text{Energy Use for Heating (MMBtu)} \div \left[\text{Fractional Boiler Efficiency} \times \left(1 - \text{Fractional Transport Losses}\right)\right]$$

steam can be found in standard steam tables. The enthalpy of saturated water at the reference conditions is 180 Btu per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation III.9e.

Step 2: Determine the energy consumed by the steam or district heating plant.

Once you have estimated your steam consumption, you can estimate the energy consumed at the steam or district heating plant by dividing your energy consumption by the system efficiency. If you can obtain information about the efficiency of the boiler used to produce the steam or hot water and any transport losses that occur in delivering the steam, use Equation III.9f. If transport losses or boiler efficiency vary seasonally, energy input should be calculated on a monthly or seasonal basis, and summed together to arrive at the total annual energy input for Step 4.

Estimated System Efficiency. As shown in Equation III.9g, if you are unable to obtain the system efficiency, divide energy consumption from Step 1 by an estimated total efficiency—boiler efficiency and transport losses combined—of 75%.

Equation III.9g — Energy Input (plant efficiency unknown)

$$\text{Energy Input (MMBtu)} = \text{Energy Consumption (MMBtu)} \div 0.75$$

Step 3: Determine appropriate emission factors.

Because emissions will vary with fuel type, you need to know the type of fuel that is burned in the plant supplying your steam or hot water. You can obtain this information from the plant's energy supplier. Once you have the type of fuel being combusted to generate the steam or hot water, use the emission factors for stationary fuel combustion in Appendix C, Tables C.7, C.8, and C.9.

Step 4: Calculate total emissions from imported steam or district heating.

Once you have both the value of total energy consumed from Step 2 and the appropriate emission factor from Step 3, use Equation III.9h to calculate total GHG emissions from imported steam or hot water.

Equation III.9h — Total Emissions from Steam System

$$\text{Total Emissions (metric tons)} = \text{Energy Consumed (MMBtu)} \times \text{Emission Factor (kg/MMBtu)} \times 0.001\ \text{metric tons/kg}$$

Step 5: Convert any CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

III.9.3 Calculating Indirect GHG Emissions from District Cooling

When you purchase cooling services using district cooling, the compressor system that produces the cooling is driven by either electricity or fossil fuel combustion. Your indirect emissions from district cooling represent your share of the total cooling demand from the cooling plant, multiplied by the total GHG emissions generated by that plant. You can begin the process of estimating your indirect emissions from district cooling by summing together the total cooling on your monthly cooling bills.

Once you have determined your total cooling, you can use one of two options—either a simplified or more detailed approach—to estimate your GHG emissions.

Simplified Approach (Option 1). The simplified approach uses an estimated value for the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP). Thus, this approach allows you to estimate the portion of energy used at the district cooling plant directly attributable to your cooling.

Detailed Approach (Option 2). COPs for chillers may vary by more than an order of magnitude, making it necessary to obtain the COP for the cooling plant. The more detailed

approach allows you to determine the total cooling-related emissions from the district cooling plant and your fraction of total load hours.

Simplified Approach Using an Estimated Coefficient of Performance - Option 1

Step 1: Determine your annual cooling demand.

While your cooling bill may be reported in terms of million Btu (MMBtu), it will typically report cooling demand in ton-hours. You can convert ton-hours of cooling demand to MMBtu using Equation III.9i. If you are billed monthly, sum together your cooling demand for every month to yield an annual total.

Equation III.9i	Annual Cooling Demand					
Cooling Demand (MMBtu)	=	Cooling Demand (ton-hours)	x	12,000 (Btus/ton-hour)	x	0.000001 (MMBtu/Btu)

Step 2: Estimate COP for the plant's cooling system.

If you are able to obtain the COP for the cooling plant, proceed to Step 3. However, if you cannot obtain the COP itself, try to determine the type of chiller used by the district cooling plant. With that information, a rough estimate of the COP may be selected from the typical values shown in Table III.9.1.

Table III.9.1 Typical Chiller Coefficients of Performance

Equipment Type	Coefficient of Performance (COP)	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas
Electric-Driven Compressor	4.2	Electricity

Step 3: Determine energy input.

To determine the energy input to the system resulting from your cooling demand, use Equation III.9j.

For an electric driven compressor, convert the energy input in MMBtu into kWh by multiplying by 293.1.

Equation III.9j	Energy Input from Cooling Demand			
Energy Input (MMBtu)	=	Cooling Demand (MMBtu)	÷	COP

Step 4: Calculate total GHG emissions resulting from cooling.

Where Cooling Plant Uses Absorption Chillers or Engine-Driven Compressors. If you can determine what type of fuel is being used, multiply the energy input by the appropriate emission factor in Appendix C, Tables C.7, C.8, and C.9. If the fuel type cannot be determined, assume natural gas and multiply the energy input by the emission factors for natural gas according to Equation III.9k.

Equation III.9k	Total Cooling Emissions - Simplified Approach					
Total Cooling Emissions (metric tons)	=	Energy Input (MMBtu)	x	Emission Factor (kg/MMBtu)	x	0.001 metric tons/kg

Where Cooling Plant Uses Electric-Driven Compressors. If the cooling plant uses an electrically driven compressor, calculate emissions using the procedures described in Chapter 6 on indirect emissions from electricity consumption.

Detailed Approach Based on Cooling Plant Emissions and Your Organization's Share of Total Cooling Demand - Option 2

Step 1: Determine total cooling-related emissions from the district cooling plant.

District cooling plants take a variety of forms and may produce electricity, hot water or steam for sale in addition to cooling.

Where Cooling Plant Produces Only Cooling. In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, you will be able to determine total cooling emissions based on 1) total indirect emissions from cooling plant electricity and heat consumption (metric tons) and 2) total direct emissions from cooling plant fuel combustion (metric tons).

The process for calculating the indirect and direct emissions is described in Sections III.6 and III.8. You will need to obtain the emission values from the district cooling plant or calculate the emissions based on the fuel consumption, as well as electricity and steam consumption information, provided by the plant.

Where Cooling Plant Produces More than Cooling. In many cases, the simple situation described above will not

apply. Instead, the cooling plant will be integrated into a combined heat and power plant, where some of the steam and electricity produced by the plant may be used for cooling, and some may be used for other purposes. In this case, the emissions from the combined heat and power plant will need to be allocated between heating and electricity production (or shaft work in the case of internal combustion engines), and these emissions will have to be scaled by the fraction of the heat or electricity that is used for cooling, as shown in Equation III.9l, which assumes 90% efficiency for boiler emissions and allocates all other waste heat to electrical efficiency.

The attribution of emissions to the heat and power streams is done in the same manner as described above.

Step 2: Determine fraction of cooling emissions attributable to your operations.

The next step in calculating your GHG emissions from cooling is to scale the total plant cooling emissions by the percentage of your share of the cooling load. Equation III.9m demonstrates how the total cooling load on the plant is scaled to determine your cooling emissions.

Step 3: Determine total yearly emissions.

For each month (or longer period) of the year, cooling emissions should be calculated as described in Steps 1 and 2, above. The duration of the periods for which the emissions are calculated will depend on the data available. Ideally, calculations would be made monthly for cooling plants integrated with CHPs, as emissions associated with cooling will depend on how the CHP outputs are distributed. If data for making these calculations are not available on a monthly basis, then longer periods will be used. In either case, the emissions for each period must be summed over the year to obtain the annual total.

Additional guidance on estimating GHG emissions from co-generation electricity and heat can be found through the following:

- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council for Sustainable Development (October 2001). The tool entitled *Calculating CO_2 Emissions from Stationary Sources* addresses emissions from co-generation facilities (www.ghgprotocol.org/standard/tools.htm).
- Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme, prepared by the U.K. Department for Environment, Food and Rural Affairs (August 2001) (www.defra.gov.uk/environment/climatechange/trading).
- EPA Climate Leaders Inventory Protocol, U.S. Environmental Protection Agency (in development as of August 2002). EPA's protocol includes a module focusing on indirect emissions from electricity and/or steam purchases (www.epa.gov/climateleaders/index).

Equation III.9l — Cooling Emissions (from plant with multiple product streams)

$$\text{Total Cooling Emissions (metric tons)} = \left[\text{Fraction of CHP Electricity Prod. Used for Cooling} \times \left(\left(\text{Total Fuel Heat Input (MMBtu)} - \text{Net Heat Production (MMBtu)} \right) \div 0.9 \right) \div \text{Total Fuel Heat Input (MMBtu)} \right]$$

$$+ \left[\text{Fraction of CHP Heat Prod. Used for Cooling} \times \left(\text{Net Heat Production (MMBtu)} \div \left(0.9 \times \text{Total Fuel Heat Input (MMBtu)} \right) \right) \right] \times \text{Total CHP Emissions (metric tons)}$$

Equation III.9m — Annual Cooling Emissions

$$\text{Participant Cooling Emissions (metric tons)} = \text{Total Cooling Emissions (metric tons)} \times \left(\text{Participant Cooling Load (ton-hour)} \div \text{Total Cooling Load (ton-hour)} \right)$$

III.9.4 Example: Indirect Emissions from District Heating

Socal Manufacturing Company

The Socal Manufacturing Company imports steam at its Bakersfield facility. The steam is imported from a conventional natural gas-fired boiler. The boiler efficiency is 85% and the loss factor is 6%.

Step 1: Determine energy obtained from steam or district heating.

Since its energy consumption is provided in therms on its monthly billing, Socal uses Equation III.9d to determine energy consumption. Socal consumed 6,000 therms in the past year.

Equation III.9d	Energy Consumption for Steam					
Steam Energy Consumption (MMBtu)	=	6,000 Therms	x	0.1 MMBtu/ therm	=	600 MMBtu

Step 2: Determine the energy consumed by the steam or district heating plant.

Socal uses its boiler efficiency of 85% and loss factor of 6% to calculate its Energy Input.

Equation III.9f	Energy Input												
Energy Input (MMBtu)	=	600 MMBtu	÷	[	0.85 (boiler efficiency)	x	(	1	-	0.06	)	]	= 750.94 MMBtu

Step 3: Determine appropriate emission factors.

Since natural gas is used to generate the steam, use emissions factors in MMBtu from Appendix C, Tables C.7 and C.8

Emission Factors for Natural Gas

Fuel	Gas Emitted	Emission Factor
Natural Gas	Carbon Dioxide	53.06 kg/MMBtu
Natural Gas	Methane	0.0010 kg/ MMBtu
Natural Gas	Nitrous Oxide	0.0001 kg/MMBtu

Step 4: Calculate total emissions.

Steam-related methane and nitrous oxide emissions are likely to be de minimis.

Equation III.9k	Total Emissions							
Total Carbon Dioxide (CO_2) Emissions (kg)	=	750.94 MMBtu	x	53.06 kg/MMBtu	x	0.001 metric tons/ kg	=	39.85 metric tons CO_2
Total Methane (CH_4) Emissions (kg)	=	750.94 MMBtu	x	0.0010 kg/MMBtu	x	0.001 metric tons/ kg	=	0.00075 metric tons CH_4
Total Nitrous Oxide (N_2O) Emissions (kg)		750.94 MMBtu	x	0.0001 kg/MMBtu	x	0.001 metric tons/ kg	=	0.000075 metric tons N_2O

Step 5: Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent					
Metric Tons of CO_2e		Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2	=				=	39.85 metric tons CO_2e
CH_4 Metric Tons of CO_2e	=	0.00075 metric tons CH_4	x	21 (GWP)	=	0.0158 metric tons CO_2e
N_2O Metric Tons of CO_2e		0.000075 metric tons N_2O	x	310 (GWP)	=	0.0233 metric tons CO_2e
				Total	=	39.89 metric tons CO_2e

Chapter 10 Direct Emissions from Sector-Specific Processes

> **Who should read Chapter 10:**
> Chapter 10 applies to organizations with process emissions only.
>
> **What you will find in Chapter 10:**
> This chapter provides several resources you may use to calculate your direct emissions from sector-specific processes.
>
> **Information you will need:**
> Your information needs will be based on the calculation methodology you select.

The California Registry's Cement Protocol provides guidance for calculating CO_2 emissions associated with manufacturing cement. Cement companies should refer to this document for procedures to account for process-related emissions from the calcination of clinker.

Power companies and utilities should refer to the Power/Utility Protocol for guidance on accounting for process-related emissions associated with emission control technologies, coal gasification, and hydrogen production.

A variety of useful resources exist that will help you calculate process emissions for which the California Registry does not provide guidance. The California Registry recommends reviewing relevant methodologies and/or calculations with technical assistance providers or other environmental experts.

Verification of emissions from manufacturing processes will be determined by the expertise and professional judgment of the verifier. Should you have questions about criteria or questions about a verifier's judgments during the verification cycle, you can contact the California Registry at any time.

The following is a list of resources for use in making your calculations:

Adipic acid production (process N_2O emissions)

- IPCC, *2006 Guidelines*, Equation 3.8
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Adipic Acid*, 2008

Aluminum production (process CO_2 and PFC emissions)

- CO_2: IPCC, *2006 Guidelines*, Equations 4.21 - 4.24
- PFC: IPCC, *2006 Guidelines*, Equations 4.25 - 4.27
- CO_2 and PFC: WRI/WBCSD, *Calculating CO_2 and PFC Emissions from the Production of Aluminum*, 2008

Ammonia production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equation 3.3
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Ammonia*, 2008

HCFC-22 production (process HFC-23 emissions)

- IPCC, *2006 Guidelines*, Equations 3.31 - 3.33
- WRI/WBCSD, *Calculating HFC-23 Emissions from the Production of HCFC-22*, 2008

Iron and steel production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equations 4.9 - 4.11
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Iron and Steel*, 2008

Lime production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equations 2.5 - 2.7
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Lime*, 2008

Nitric acid production (process N_2O emissions)

- IPCC, *2006 Guidelines*, Equation 3.6
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Nitric Acid*, 2008

Pulp and paper production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Section 2.5
- International Council of Forest and Paper Associations (ICFPA), *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, Version 1.1, 2005
- European Union, *Guidelines for the monitoring and reporting of greenhouse gas emissions*, 2006, Annex XI
- WRI/WBCSD, *Calculating GHG Emissions from Pulp and Paper Mills*, 2005

Semiconductor manufacturing (process PFC and SF_6 emissions)

- IPCC, *2006 Guidelines*, Equations 6.7 - 6.11
- WRI/WBCSD, *Calculating PFC Emissions from the Production of Semiconductor Wafers*, 2001

Other Resources

- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council

for Sustainable Development. The calculation tools are available from the GHG Protocol Initiative website at www.ghgprotocol.org/standard/tools.htm.

- EPA Climate Leaders Greenhouse Gas Inventory Guidance, U.S. Environmental Protection Agency, provides modified guidance from the World Resources Institute and World Business Council for Sustainable Development. See www.epa.gov/climateleaders/index.html.

Chapter 11 Direct Fugitive Emissions

Who should read Chapter 11:

Chapter 11 applies to organizations with fugitive emissions only.

What you will find in Chapter 11:

This chapter provides guidance on determining direct fugitive emissions, specific guidance and an example on fugitive refrigerant emissions of HFCs, and guidance on additional resources to use for other fugitive emissions.

Information you will need:

To complete this chapter you will need information on the types and quantities of air conditioning equipment, total refrigerant charge, annual leak rates, and the types of refrigerant, as applicable.

Cross-References:

See Chapter 5 on De Minimis Emissions and Significance in estimating HFCs from refrigerants.

Power companies and utilities should refer to the Power/Utility Protocol for guidance on accounting for fugitive emissions associated with electricity transmission and distribution, fuel handling and storage, air conditioning and refrigerant systems, and fire suppression equipment.

The majority of fugitive GHG emissions are specific to various industrial sectors or processes, including: manufacturing, natural gas transport and distribution, coal mining, waste management, wastewater treatment, and refrigerant leakage from air conditioning and refrigeration equipment. This chapter provides specific guidance on direct fugitive emissions from air conditioning, refrigeration, and fire suppression systems below. It also provides a list of resources for calculating other types of fugitive emissions.

III.11.1 Calculating Direct Fugitive Emissions from Refrigeration Systems

Leakage from refrigeration systems, such as air conditioners and refrigerators, is common across a wide range of entities. Only those refrigerants that contain or consist of compounds of the required GHGs should be reported (see Table III.11.1). Hydrofluorocarbons (HFCs) are the primary GHG of concern for refrigeration systems, particularly for motor vehicle air conditioners. Today, HFC-134a is the standard refrigerant for mobile air conditioning systems. For most California Registry participants, emissions of HFCs from refrigeration, air conditioning systems, and fire suppression equipment will be negligible in comparison to other GHG emissions.

Table III.11.1 HFCs and PFCs to be Reported

HFC-23	HFC-143a	HFC-4310mee	C_4F_{10}
HFC-32	HFC-152a	CF_4	C_6F_{14}
HFC-125	HFC-227ea	C_2F_6	
HFC-134a	HFC-236fa	C_3F_8	

Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003, Table 1-2 (April 2005).

Please note that many common refrigerants are blends of multiple HFCs. Table III.11.2 provides some examples of refrigerant blends and their composition. When calculating the emissions related to refrigerant blends, these blends must be broken down and reported as their constituent parts.

Table III.11.2 Composition of Refrigerant Blends

Blend	HFC 32	HFC-125	HFC-134a	HFC-143a
R404A	NA	44%	4%	52%
R407C	23%	25%	52%	NA
R507	NA	50%	NA	50%
R507	NA	50%	NA	50%

Use the following three step process to calculate HFC emissions:

1. Determine whether HFC emissions are significant or de minimis (see Chapter 5 for guidance on de minimis);
2. Perform a mass balance calculation; and
3. Convert each HFC emission to CO_2e.

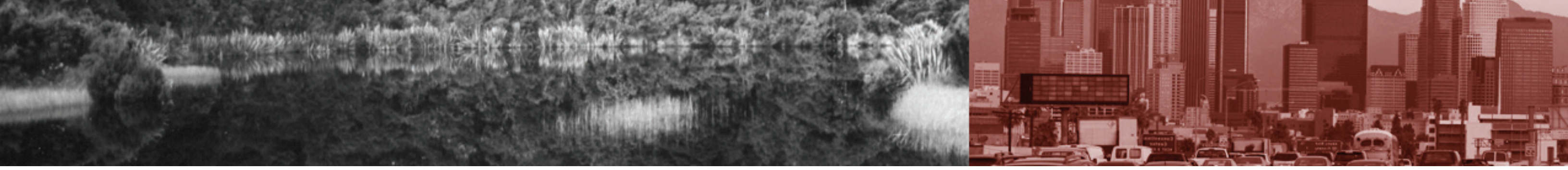


Table III.11.3 Loss Rates for Refrigeration and Air Conditioning Equipment
Note that all values are estimates and are intended only to serve as guidelines for evaluating de minimis.

Type of Equipment	Capacity (kg)	Annual Loss Rate (% of capacity)
Domestic Refrigeration	0.05 – 0.5	0.5%
Stand-alone Commercial Applications	0.2 – 6	15%
Medium & Large Commercial Refrigeration	50 – 2,000	35%
Transport Refrigeration	3 – 8	50%
Industrial Refrigeration (including food processing and cold storage)	10 –10,000	25%
Chillers	10 – 2,000	15%
Residential and Commercial A/C (including heat pumps)	0.5 – 100	10%
Mobile Air Conditioning	0.5 – 1.5	20%

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Volume 3: Industrial Processes and Product Use, Table 7.9.

Step 1 estimates whether your fugitive emissions are significant and warrant a more comprehensive review. If the fugitive emissions are not significant, and you wish to categorize them as de minimis, you do not need to complete this section. To perform the significance analysis, you will need information on:

- The types and quantities of air conditioning and refrigeration equipment;
- The total refrigerant charge;
- The annual leak rates; and
- The types of refrigerant.

If you find that your fugitive emissions are indeed significant, continue to Steps 2 and 3 for a more accurate quantification of HFC emissions.

Step 1: Determine whether HFC emissions are significant or de minimis.

This step helps organizations roughly estimate emissions and determine whether HFC emissions are significant or de minimis. Consistent with the California Registry's definition of significance, fugitive HFC emissions greater than or equal to 5% of a participant's total emissions are considered significant, assuming the participant has no other de minimis emissions. Fugitive emissions less than 5% can be considered de minimis, and should be reported as such. However, if fugitive emissions are considered substantial and possibly significant, then a more comprehensive and accurate mass balance approach is required to determine actual emissions.

Ozone Depleting Refrigerants and Climate Change

Did you know that not all refrigerants that affect climate change are considered greenhouse gas emissions? A number of widely-used refrigerants, including R-22 (more commonly known as Freon), are classified as ozone depleting substances (ODS) and are being phased out under the Montreal Protocol, an international treaty designed to protect the ozone layer that entered into force in 1989. While these substances do have a global warming potential, and therefore contribute to climate change, they are not classified as greenhouse gas emissions under the Kyoto Protocol because they are already being phased out under the Montreal Protocol.

When assessing your fugitive emission sources, please keep in mind that CFCs and HCFCs, including Freon, should not be included in your emissions report. You should only include emissions of the HFCs and PFCs listed in Table III.11.1 in this chapter. For more information on ozone-depleting substances and the Montreal Protocol, visit EPA's ozone depletion website at www.epa.gov/ozone/strathome.html.

To estimate emissions using this estimation method, follow these three steps:

- Determine the types and quantities of refrigerants used;
- Estimate annual emissions of each type of HFC; and
- Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number and types of refrigeration and air conditioning equipment, by equipment category; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment. If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table III.11.3.

Estimate annual emissions of each type of HFC.

For each type of HFC, use Equation III.11a to estimate annual emissions. Default loss rates are provided in Table III.11.3 by equipment type.

Equation III.11a	HFC Emissions from Refrigerant Leakage			
HFC Emissions from Refrigerant Leakage (kg)	=	Total Annual Refrigerant Charge (kg)	x	Assumed Annual Leak Rate (%)

Convert HFCs to carbon dioxide equivalent.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert HFCs to carbon dioxide equivalent. If the sum of the CO_2e emissions for HFCs (plus other estimated de minimis emissions) is less than 5% of total assumed emissions, report these emissions as de minimis; no further calculations are needed.

Proceed to Steps 2-3 if your HFCs are significant.

Step 2: Mass Balance Calculation: Determine base inventory for each HFC and calculate changes to base inventory.

Step 2 utilizes a comprehensive, mass balance approach to accurately determine HFC emissions. Essentially, the mass balance method works by starting with a base inventory of all HFCs in use, and adjusts that total based on purchases and sales of HFCs, and changes to the total refrigerant charge remaining in the equipment. The used HFCs that cannot be accounted for are assumed to have been emitted to the atmosphere. The four elements of these adjustments and changes are described here, with references to Tables III.11.4 and III.11.5, as applicable.

Base Inventory. The first step in calculating HFC emissions is to determine the difference between the quantity of the HFC in storage at the beginning of the year **(A)** and the quantity in storage at the end of the year **(B)**, as shown in Table III.11.4. Note, this quantity will be negative if the inventory increases over the course of the year. Those HFCs contained in cylinders and other storage containers are considered to be HFCs "in inventory"—not HFCs held in operating equipment.

Table III.11.4 Base Inventory

	Inventory	Amount (kg)
A	Beginning of year	
B	End of year	

Table III.11.5 Inventory Changes

	Inventory	Amount (kg)
	Additions to Inventory	
1	Purchases of HFCs (including HFCs in new equipment)	
2	HFCs returned to the site after offsite recycling	
C	Total Additions (1+2)	
	Subtractions from Inventory	
3	Returns to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and sent offsite for recycling or reclamation	
D	Total Subtractions (3+4+5)	
	Change to Full Charge/Nameplate Capacity	
6	Total full charge of new equipment	
7	Total full charge of retiring equipment	
E	Change to nameplate capacity (6-7)	

Additions and subtractions refer to HFCs placed in or removed from the stored inventory, respectively. The next items in calculating HFC emissions include purchases or acquisitions of refrigerant, sales or disbursements of refrigerant, and any changes to total full charge of refrigeration equipment.

Purchases/Acquisitions of Refrigerant. This is the sum of all the HFCs acquired during the year either in storage containers or in equipment **(C)**, as shown in Table III.11.5.

Sales/Disbursements of Refrigerant. This is the sum of all the HFCs sold or otherwise disbursed during the year either in storage containers or in equipment **(D)**, as shown in Table III.11.5.

Change to Total Full Charge of Equipment. This is the net change to the total equipment volume for a given HFC during the year **(E)**, as shown in Table III.11.5.

Note that the change to total full charge of equipment refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new equipment is purchased, the HFC 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 refrigerant recovered from retiring equipment is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring equipment has a total full charge larger than the total full charge of the new equipment.

To sum the total annual emissions of each type of HFC, use Equation III.11b.

Equation III.11b	Total Annual Emissions from Refrigerant Leakage
Total Annual Emissions	= A - B + C - D + E

Step 3: Convert HFC emissions to CO_2e (and convert to metric tons) and sum all subtotals.

Finally, use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert each HFC to carbon dioxide equivalent, and sum the totals.

III.11.2 Fugitive Emissions from Fire Suppression Equipment

Your organization may use HFCs in its fire suppression equipment, including hand-held fire extinguishers. HFCs are the most widely employed replacements for Halon 1301 in total flooding applications, and are also employed as replacements for Halon 1211 in streaming applications. Since the production and sale of halons were banned in the United States in 1994, these non-ozone depleting extinguishing agents have emerged as the halon replacement agent of choice in some applications.

As fire protection equipment is tested or deployed, emissions of these HFCs are released. Thus, if you own or operate fire suppression systems and equipment and have tested or deployed these systems, you should assess whether any HFCs have been released. The mass balance approach described in Section III.11.1 can be used for determining emissions from fire suppression systems.

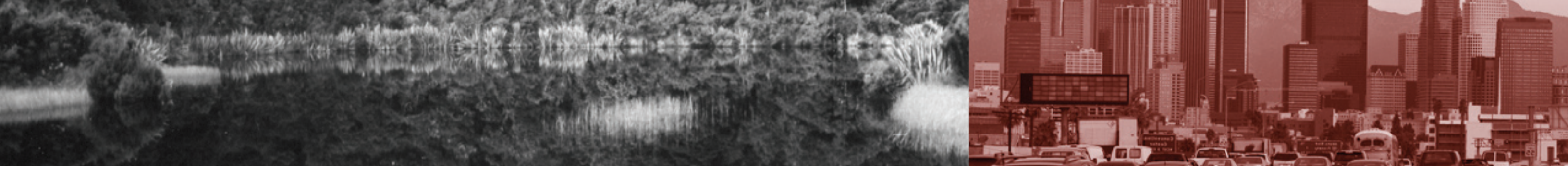
III.11.3 Other Fugitive Emissions

A variety of useful resources exist that may help you to calculate other fugitive emissions. The California Registry recommends reviewing relevant methodologies and/or calculations with technical assistance providers or other environmental experts.

Verification of fugitive emissions will be determined by the expertise and professional judgment of the verifier. Should you have questions about criteria or questions about a verifier's judgments during the verification cycle, you can contact the California Registry at any time.

The following is a list of resources for use in making your calculations:

- Local Government Operations Protocol, California Climate Action Registry. This protocol provides guidance on reporting methane emissions from solid waste facilities and methane and nitrous oxide emissions from wastewater facilities (www.climateregistry.org).
- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council for Sustainable Development (2004) (www.ghgprotocol.org/standard/tools.htm).
- Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme, prepared by the U.K. Department for Environment, Food and Rural Affairs (August 2001) (www.defra.gov.uk/environment/climatechange/trading).
- EPA Climate Leaders Inventory Protocol, U.S. Environmental Protection Agency (in development as of August 2002). EPA's protocol includes core modules addressing methane emissions from solid waste disposal at landfills as well as HFC emissions from refrigeration/air conditioning use (www.epa.gov/climateleaders/index.html).



- Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000, U.S. Environmental Protection Agency (April 2002) (www.epa.gov/globalwarming/publications/emissions/us2002/index.html).
- Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999, prepared by the California Energy Commission, November 2002 (www.energy.ca.gov/global_climate_change).
- American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry (2001).
- Guidance to the California Climate Action Registry: General Reporting Protocol, Appendix B and Appendix C, prepared by the California Energy Commission, P500-02-005F (June 2002), located at www.climateregistry.org. The following list of citations provide some guidance on quantifying direct fugitive emissions:
  - CH_4 emissions from coal mining: Appendix B page B-5, Appendix C page C-3
  - CH_4 emissions from natural gas systems: Appendix B page B-15, Appendix C page C-9
  - CH_4 emissions from petroleum systems: Appendix B page B-17, Appendix C page C-9
  - SF_6 emissions from electricity transmission and distribution equipment: Appendix B page B-6, Appendix C page C-4
  - N_2O emissions from wastewater: Appendix B page B-9
  - CH_4 emissions from wastewater: Appendix B page B-15
  - CH_4 emissions from landfills: Appendix B page B-10
  - N_2O emissions from agricultural soil management: Appendix B page B-2
  - CH_4 emissions from livestock as a result of enteric fermentation: Appendix B page B-7
  - CH_4 and N_2O emissions from manure management: Appendix B page B-13
  - CH_4 emissions from rice cultivation: Appendix B page B-18

III.11.4 Example: Direct Fugitive Emissions from Refrigeration Systems

Produce Chillers, Inc.

Produce Chillers, Inc. is based in California, and operates three large commercial refrigeration units, with an annual capacity of 1,225 kg HFC-23 per system, to refrigerate vegetable produce shortly after harvest, as well as three trucks that use HFC-134a for air conditioning.

Step 1: Determine whether HFC emissions are significant or de minimis.

Produce Chillers' first step is to determine whether its HFC emissions are significant. The upper bound loss rates for Produce Chiller's AC types are shown in Table III.11.3 and the excerpt below.

Air Conditioner Loss Rates for Produce Chillers, Inc.

Type of Equipment	Capacity (kg)	Annual Loss Rate (% of capacity)	Type of Refrigerant
Medium & Large Commercial Refrigeration	50 – 2,000	35%	HFC-23
Mobile Air Conditioning	0.5 – 1.5	20%	HFC-134a

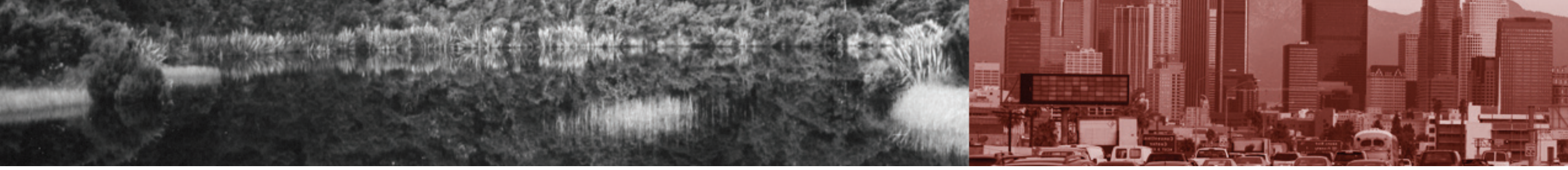
Produce Chillers then uses Equation III.11a to estimate assumed HFC emissions from air conditioning and refrigeration.

Equation III.11a	Assumed HFC Emissions from Annual Air Conditioning													
HFC Emissions from Annual Air Conditioning (kg)	=	Number of Systems	x	[	Total Annual Capacity (kg)	x	Operating Loss Rate (%/yr)	x	Years	]	÷	1,000		
3 Commercial Refrigeration Units	=	3	x	[	1,225	x	0.35	x	1	]	÷	1,000	=	1.286 metric tons HFC-23
3 Trucks	=	3	x	[	1.5	x	0.20	x	1	]	÷	1,000	=	0.0009 metric tons HFC-134a

Produce Chillers must then convert its assumed fugitive HFCs to CO_2e, using Equation III.6c

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent				
HFC-23 metric tons of CO_2e	=	1.286 metric tons HFC-23	x	11,700 (GWP)	= 15,046.2 metric tons CO_2e
HFC-134a metric tons of CO_2e	=	0.0009 metric tons HFC-134a	x	1,300 (GWP)	= 1.17 metric tons CO_2e
				Total	= 15,047.37 metric tons CO_2e

Produce Chillers has estimated that its total entity-wide GHG emissions are 50,000 metric tons. Consequently, they may choose to report up to 2,500 metric tons (i.e., 5% of 50,000 metric tons) as de minimis emissions. Its estimated fugitive emissions of HFC-23 are found to be significant, but HFC -134a can be classified and reported as de minimis. It must now calculate its HFC-23 emissions.



Step 2: Determine base inventory for HFC-23 and calculate changes to base inventory.

Produce Chillers increased its total vegetable produce refrigeration capacity by 18% with new equipment, decommissioned one refrigeration unit for recycling, and recharged several of its refrigeration units. It also purchased a new truck in the past year. Using Table III.11.4 it shows that the inventory at the beginning of the year is 812.6 kg and at the end of the year it is 805.1 kg.

Base Inventory for Produce Chillers, Inc.
HFC-23 from Commercial Chillers

	Inventory	Amount (kgs)
A	Beginning of year	812.6
B	End of year	805.1

Using its purchase and charge records, Produce Chillers calculates its total annual emissions using Table III.11.5 and Equation III.11b

Inventory Changes for Produce Chillers, Inc.
HFC-23 from Commercial Chillers

	Inventory	Amount (kgs)
	Additions to Inventory	
1	Purchases of HFCs (including HFCs provided by equipment manufacturers with or inside new equipment)	197.5
2	HFCs returned to the site after offsite recycling	0.0
C	Total Additions (1+2)	197.5
	Subtractions from Inventory	
3	Returns of HFCs to supplier	0.0
4	HFCs taken from storage and/or equipment and disposed of	0.0
5	HFCs taken from storage and/or equipment and sent offsite for recycling or reclamation	53.3
D	Total Subtractions (3+4+5)	53.3
	Change to Full Charge/Nameplate Capacity	
6	Total full charge of new equipment	19.5
7	Total full charge of retiring equipment	0.0
E	Change to nameplate capacity (6-7)	19.5

Equation III.11b	Total Annual Emissions of HFC-23 (kgs)			
Total Annual Emissions	=	A - B + C - D + E		
Total Annual Emissions HFC-23	=	812.6 – 805.1 + 197.5 – 53.3 + 19.5	=	171.2 kg HFC-23

Step 3: Convert HFC emissions to CO_2e and convert to metric tons.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent							
Metric tons of CO_2e	=	Metric tons of GHG	x	GWP (SAR, 1996)				
HFC-23 metric tons of CO_2e	=	132.2 kg HFC-23	x	11,700 (GWP)	x	0.001 metric tons/kg	=	1.5467 metric tons CO_2e
						Total	=	1.5467 metric tons CO_2e

Chapter 12 Optional Reporting

> **Who should read Chapter 12:**
>
> Chapter 12 applies to all participants.
>
> **What you will find in Chapter 12:**
>
> This chapter provides resources for calculating and/or estimating emissions from sources that are not required to be reported, such as from employee commuting, business travel, waste, and more.
>
> **Information you will need:**
>
> You will need information about the size and nature of GHG emitting operations throughout your organization.
>
> **Cross-References:**
>
> It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, operational boundaries considered in Chapter 3, and all relevant quantification issues raised in Chapters 5-11.

In addition to reporting required emissions, you can also provide information to the California Registry about other activities of your organization that can help describe your entity's GHG activities and inventory.

Examples of these include:

- Renewable Energy Certificate purchases;
- Off-site waste disposal, including transport;
- Employee commuting, including business travel;
- Production of purchased raw materials, including transport;
- Product use and disposal; and
- Outsourced activities and contracting (especially if, in prior years, you generated these emissions directly).

You can also provide descriptive information about your organization's programs, projects to reduce emissions, environmental goals, and awards and choose to provide quantitative information, including reporting of emissions efficiency metrics or other indirect emissions.

A key feature of the California Registry's program is the reporting of efficiency metrics. GHG emissions are sometimes reported on a normalized basis – as a ratio – instead of, or in addition to, reporting in absolute terms. Normalized emissions are emissions divided by some measure of output for the reporting entity. The specific output measure depends on the nature of the organization that is reporting and may range from physical units of output (e.g., pound of cement for a cement plant) to economic output (e.g., dollars of revenue for a diversified manufacturer). Reporting normalized emissions allows trends in the emissions intensity of an activity to be gauged by removing the effects of changing outputs on the results. The common term for these measures is "efficiency metrics". Sample efficiency metrics are listed in Appendix F.

III.12.1 Reasons to Report Optional Information

There are potentially many reasons to report optional information:

- To provide a more complete or descriptive picture of your organization's environmental performance.
- To centralize information pertaining to other GHG accounting programs.
- To track other internal programs to monitor GHG emissions performance related to other corporate programs.
- To provide greater public education on sources of GHG emissions.

There are no California Registry-approved protocols for reporting or verifying optional information. Even so, reporting optional sources can serve to improve your organization's understanding of its emissions and its emission performance over time.

Also, the California Registry encourages you to document and report your GHG emissions internationally in the same categories as you report your California or U.S. emissions. While international emissions cannot currently be verified with the California Registry, doing so will only increase your ability to measure and manage your total emissions.

In the process of developing industry-specific guidance, additional recommendations may be developed for optional information reported by industry.

III.12.2 Efficiency Metrics

Many organizations experience business growth and thus their total emissions may increase from year-to-year, regardless of their organization's operational efficiency. Such organizations, in addition to reporting their total

emissions, may also elect to report efficiency metrics that measure GHG emissions per unit of performance or output (e.g., lbs CO_2/ft^2 of office space, lbs CO_2/customer, lbs CO_2/kWh, lbs CO_2/$ of revenue, etc.). A list of some industry-specific metrics is provided in Appendix F. This information may be reported in CARROT at either the entity- or facility-level, but CARROT is not able to calculate this statistic for you.

For organizations reporting under the General Reporting Protocol, metrics are optional. As the California Registry develops its industry-specific reporting guidance, affected industries may be required to report one or more metrics appropriate to their industry; for instance, power sector companies are required to report three metrics according to the Power/Utility Protocol as well as cement companies under the Cement Protocol.

III.12.3 Other Emissions Information

When reporting information in CARROT, the tool will prompt you to provide descriptive information about your organization in the following areas:

Entity description – You can provide basic information about your organization, including size, types of business and products, number of employees, etc.

Emission management programs—In this section, you can document the efforts of your organization to monitor and evaluate how and where your organization is producing GHG emissions. This could also include a description of other GHG accounting programs to which your organization belongs.

Emission reduction goals –You can enter information on your organization's goals to decrease your emissions of GHGs.

Emission reduction projects—Until additional guidance is developed to provide standardized, verifiable accounting principles for discrete projects to reduce emissions, you can provide descriptions of specific activities, as well as provide a limited amount of statistical information.

Link to external website—You can provide a link or links to external websites that contain information about your organization.

Space constraints in CARROT may limit how much information can be entered, but you can provide your own categories and update this information from year-to-year. You can also upload related documents in CARROT and attach them to your public emissions report.

III.12.4 Optional Indirect Emissions

In addition to reporting indirect emissions from your electricity use, you are encouraged to optionally report other indirect GHGs. Examples of other sources of indirect emissions that you may choose to report include:

- Off-site waste disposal, including transport;
- Employee commuting, including business travel;
- Production of purchased raw materials, including transport;
- Product use and disposal; and
- Outsourced activities and contracting.

The California Registry is still formulating specific guidance on estimating emissions from additional indirect sources such as those listed above. However, a variety of useful resources exist that may help you to estimate emissions from these types of activities. Some of these include:

Off-site waste disposal, including transport

- EPA Climate and Waste Program, yosemite.epa.gov/oar/globalwarming.nsf/WARM?OpenForm

Employee commuting, including business travel

- Calculating GHG emissions from office-based organizations, www.ghgprotocol.org/calculation-tools and www.ghgprotocol.org/calculation-tools/service-sector
- Safe Climate, www.safeclimate.net/calculator
- Climate Care, www.climatecare.org/business

The California Registry will review optionally reported information of participants. It reserves the right to ask for appropriate modifications or removal of specific optionally reported information, if it deems such changes are necessary.

III.12.5 Biogenic Emissions

Biogenic CO_2 emissions are produced from combusting a variety of biofuels, such as biodiesel, ethanol, wood, wood waste, and landfill gas.

International consensus on the net climate impact from the combustion of these fuel sources has not yet been reached. But because of the distinction between biogenic and anthropogenic emissions, the emissions associated with the biofuels should not be included as direct stationary or mobile emissions in your inventory.

The GRP provides limited guidance on calculating and reporting biogenic emissions because participants are only required to report anthropogenic emissions in their emissions inventory. However, biogenic emissions may be reported optionally. Chapter 7 contains guidance to calculate mobile CO_2 emissions from biodiesel, and biogenic emission factors for mobile and stationary combustion are available in Appendix C, Tables C.3 and C.7, respectively, to aid in reporting these optional biogenic sources.

Please note that CH_4 and N_2O emissions from the combustion of biofuels are not considered biogenic and should be calculated and reported as part of your emissions inventory.


Part IV Completing and Submitting Your Report

Now that you have established your reporting parameters in Part II and quantified your emissions in Part III, you are ready to complete your annual GHG emissions report, verify your emissions, and submit your inventory to the California Registry.

Chapter 13, Reporting Your Emissions, describes the steps you need to follow to report your emissions using CARROT, the California Registry's online reporting tool, and the *CARROT Getting Started Guide Version 3* as well as the steps for formally registering your emissions report with the California Registry once you have received verification from a verifier.

Chapter 14, Verification, explains the verification process. This chapter includes an overview of the importance of verification, requirements for meeting verification standards, the process for identifying and working with verifiers, documentation and other items you will need to prepare for verification, the reports you and the California Registry will receive at the conclusion of the process, and the process for correcting your emissions report, if necessary.

Chapter 13 Reporting Your Emissions

> Who should read Chapter 13:
>
> Chapter 13 applies to all participants.
>
> What you will find in Chapter 13:
>
> This chapter provides guidance on submitting your emissions report to and accessing your report from the California Registry.
>
> Information you will need:
>
> In order to submit your GHG emissions report, you will need a password from the California Registry, as well as all the relevant information required in your report.
>
> Cross-References:
>
> It may be useful to review the requirements in Chapter 14 on Verification.

Now that you have established your reporting parameters in Part II and quantified your emissions in Part III, you are ready to report your emissions to the California Registry using the California Registry's online reporting tool, CARROT.

IV.13.1 Submitting Your Report Using CARROT

You must report your organization's annual GHG emissions report via the California Registry's web-based reporting application and database, known as the Climate Action Registry Reporting Online Tool (CARROT).

CARROT has four main functions:

1. Helps California Registry participants calculate their annual GHG emissions and/or report these emissions to the California Registry.
2. Allows approved verifiers to review participants' annual GHG emissions reports and submit their verification information to the California Registry.
3. Permits the general public to view aggregated reports of participants' annual GHG emissions and their progress in managing these emissions.
4. Enables California Registry staff to efficiently manage and track participants' data.

CARROT provides you with a secure, online workspace to manage, report, verify, and register your emissions.

The California Registry has designed CARROT to facilitate and ease emissions reporting. CARROT is also designed to streamline the emissions registration process by providing emissions calculations tools, simple reporting features, and administrative controls that allow participants to delegate reporting within your organization.

When you join the California Registry, your organization's technical contact will be provided a UserID and Password that will allow you to access CARROT through the California Registry's website, www.climateregistry.org/CARROT. Other users within your organization can request access from your organization's technical contact.

IV.13.2 CARROT Guidance and Technical Assistance

If you have questions about using CARROT, the California Registry provides reporting assistance and support through the following tools:

- *CARROT Getting Started Guide Version 3* (December 2008), available on the California Registry website in PDF format
- CARROT online help and online documentation
- Email user support at help@climateregistry.org
- Phone user support (213-891-1444, extension 2)

Prospective participants and other interested parties can see how CARROT works by viewing a short demonstration of the tool, accessible on the California Registry's website (www.climateregistry.org/CARROT/Demo). Participants can also familiarize themselves with CARROT by using the CARROT Training Site. Access to the training site may be requested by sending an email to help@climateregistry.org.

IV.13.3 Accessing Your Verified Emissions Data

CARROT provides a variety of tools to help you manage and use your emissions data, and will be regularly updated to reflect current emissions reporting policies. The following are some of the features that will assist you in managing your reported GHG emissions information.

Participant's Administrative Module

CARROT allows you to manage separate emissions submissions, as needed, from within your organization, depending on how many individuals are responsible for reporting a subset of your total GHG emissions report. This is done by creating different types of users within CARROT.

Administrators are responsible for managing each entity's annual emissions report, creating other users to help them input or review data, and submitting an entity's report for verification and finally to the California Registry. They have full read/write access to data for all reported years.

Users are assigned to one or more facilities, and can enter information for specific locations for specific years and submit it to the Administrator for review.

For example, if your organization owns and operates five different facilities, the Administrator can grant permission to five different facility managers to enter the GHG emissions information from their respective facilities. The Administrator will be able to visually assess the status of each of the five facilities and will be the only party with the permission to submit and classify the entity emissions report as "Verification Ready".

Participant Database Query and Reporting

Once you have entered your emissions data, CARROT helps you generate detailed and summary reports of your information. Examples of CARROT reports include:

Reports for Participants

- Total Reported Emissions – Entity
- Total Reported Emissions – by Facility (if applicable)

Reports for the Public

In addition to collecting your GHG emissions data, CARROT will also make limited information about your GHG emissions report and overall California Registry participation available to the public. The public will see the following information, which you are required to report:

- Company name, address, and contact;
- Reporting year;
- Total emissions, by gas and by category (i.e., stationary combustion, mobile combustion, process emissions, fugitive emissions, indirect emissions and de minimis emissions); and
- Baseline year (if chosen).

In addition, the public will see the following information that you may choose to report. This optional information is not verified.

- Reduction goals, projects, management programs
- Entity description
- Total optional emissions, by gas and by category
- Other optional information

Archive Feature

CARROT maintains annual versions of your GHG emissions report submissions. Also, CARROT will keep copies of any revisions with your comments, to enable you to correct your submissions, and for California Registry-approved verifiers to verify your data. You can revise your report at any time; however, once it has been submitted for verification, any subsequent changes will need to be re-verified.

IV.13.4 Movement Reports

For every year of emissions data collection, CARROT will ask you to prepare a Movement Report, in which you identify the major factors that have affected your emissions. The Movement Report is required each year after your first year of reporting.
This should include:

- A list of structural changes (e.g., mergers, acquisitions, divestitures, outsourcing);
- A discussion of how your organization's business cycle is affecting your emissions; and
- A list of any emission reduction projects undertaken by your organization.

Table IV.13.1 provides a sample Movement Report.

Table IV.13.1 Sample Movement Report

Factor Affecting Performance	Details
Structural Change: Acquisition Divestiture Insourced Activities Outsourced Activities Leakage	Name Location Business Unit Affected Change due to California Registry participation Estimated impact on emissions
Organic Growth or Decline: New Construction Plant Closing Decrease in Production Increase in Production Business Cycle Fluctuation	Name Location Business Unit Affected Estimated Impacts on Production Estimated impact on emissions
Emission Reduction Activities: Purchased Offsets Avoided Emissions Sequestration	Project Name Location Estimated impact on emissions
Other	

For each category, CARROT will ask you to provide an explanation of each change to emissions, as well as an estimate of the impact on your total emissions. Thus, for an acquisition, you would indicate the name, location and size of the acquisition, and the estimated associated emissions per year (tons CO_2e/year).

One purpose of this Movement Report is to facilitate verification. Verifiers will reference this Movement Report to understand changes in your emissions data from year to year; however, this information will not be verified for accuracy nor provided to the public.

IV.13.5 Utilizing Your Verified Emissions Data

While the California Registry cannot predict the full range of ways you can utilize your verified emissions data, there are some important uses that are worth considering. For example, once you have started entering your information in the California Registry's CARROT reporting system, you will be able to maintain and track your organization's progress in meeting internal GHG reduction targets with every annual GHG emissions report.

As mentioned earlier, under a possible future regulatory regime, your verified emissions data could provide the basis for any determination of protections or other regulatory rewards for taking early steps to reduce your GHG emissions. Future regulations by the State of California or the federal government might reward organizations that took significant steps to reduce GHG emissions. Similarly, your GHG emissions data might be applicable for participating in voluntary GHG emissions reduction programs, both in the United States and abroad, or ISO 14064[1] for GHG emission reduction practices.

In addition, you may publish your verified emissions data in order to demonstrate your organization's commitment to environmental goals and to addressing climate change, and to disseminate transparent information about the specific steps your organization has taken to achieve reductions in GHG emissions.

1 The ISO 14064 standards for greenhouse gas accounting and verification published in March 2006 by ISO (International Organization for Standardization) provide government and industry with an integrated set of tools for programs aimed at reducing greenhouse gas emissions, as well as for emissions trading (www.iso.org).

Chapter 14 Verification

> **Who should read Chapter 14:**
>
> Chapter 14 applies to all participants.
>
> **What you will find in Chapter 14:**
>
> This chapter provides guidance on the process for verifying your GHG emissions report, including how to obtain verification services from an approved verifier, and what you will need to prepare for verification.
>
> **Information you will need:**
>
> Chapter 14 will guide you through the steps involved in determining what information you will need for verification. Table IV.14.1 in this chapter provides a list of specific documentation that will be needed for verification.
>
> **Cross-References:**
>
> All other chapters in the General Reporting Protocol may be considered during the verification process. In addition, you should review the General Verification Protocol, to be used by approved verifiers, in preparing for verification.

This chapter provides context for the principles underlying verification, explains the verification standards, and overviews the entire verification process.

This General Reporting Protocol is designed to direct the complete, transparent, and accurate reporting of your organization's GHG emissions. Verifying your emissions report is the final step in the reporting process.

Verification is the process used to ensure that a participant's GHG emissions report has met a minimum quality standard and complied with an appropriate set of California Registry-approved procedures and protocols for submitting emissions inventory information. For most California Registry participants, meeting the requirements of the General Reporting Protocol should be sufficient to complete verification. Where a participant is eligible for an industry-specific protocol, they will need to meet those requirements to achieve verification. Participants with relatively small and simple emissions (<500 tons CO_2e per year) may be eligible for batch verification - see Section IV.14.14 for more information on eligibility.

The California Registry's verification process has been designed to promote the credibility, accuracy, transparency, and usefulness of emissions data reported to the California Registry. Once an approved verifier has determined that the emissions report meets a minimum quality standard and is free of material discrepancies, the participant's reported emissions data will be reviewed by the California Registry and accepted into the California Registry's database.

If you are interested in understanding and preparing for the verification process in more detail, and to see the specific process approved verifiers will be using to verify your GHG emissions report, you may obtain a copy of the Verification Protocol, the California Registry's guidance for approved verifiers, from the California Registry's website.

IV.14.1 GHG Reporting Principles and Verification

The purpose of verification is to provide an independent review of data and information submitted to the California Registry, which ensures the credibility of the GHG inventories. To accomplish this objective, the independent verification process maintains the criteria of comparability, completeness, consistency, transparency, and accuracy as its underlying principles. These accounting and reporting principles are described in Section I.4.

IV.14.2 Verification Standard

At a minimum, each annual GHG emissions report (emissions report) must contain all of an entity's emissions of CO_2 in the state of California for a calendar year, reported in five categories: 1) indirect emissions from purchased electricity, imports of steam, district heating and cooling, and direct emissions from 2) mobile combustion, 3) stationary combustion, 4) process emissions, and 5) fugitive emissions. Where a participant is reporting its U.S. emissions, the report must contain all of their emissions nationally. Starting with the fourth year of reporting, each emissions report must contain all emissions of all six greenhouse gases (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6). If a participant is reporting process or fugitive emissions, a separate industry specific protocol may also be used and cited.

Emissions reports may also contain other information about an organization and its emissions that does not require verification. Your verifier will not consider this information when developing an opinion regarding your verifiable annual GHG emissions inventory results.

Additional guidance on reporting optional information is provided in Chapter 12.

IV.14.3 Minimum Quality Standard

An emissions report submitted to the California Registry must be free of material discrepancies to be verified. In other words, a verifier's calculation estimates of the entire inventory must not differ from a participant's estimates of the entire inventory by more than 5%. It is possible that during the verification process differences will arise between the emissions totals estimated by participants and those estimated by verifiers. Differences of this nature may be classified as either material or immaterial discrepancies. A discrepancy is considered to be material if the overall reported emissions differ from the overall emissions estimated by the verifier by 5% or more. Otherwise, it is immaterial.

IV.14.4 The Verification Process

The verification process outlined in the General Verification Protocol is designed to be applied consistently across all participants. However, based on the size and complexity of participants' operations and management systems, verification activities and the duration of the process will vary.

At a minimum the verification process will include the following steps:

- Conducting an evaluation of Conflict of Interest by the California Registry
- Providing notification of planned verification activities to the California Registry
- Scoping and planning a participant's verification activities prior to commencing verification
- Conducting verification activities in accordance with the General Verification Protocol
    - Identifying emissions sources
    - Reviewing methodologies and management systems
    - Verifying emission estimates
- Preparing a participant's Verification Report and Verification Opinion
- Submitting a Verification Opinion and Verification Activity Log to the Participant

Upon the completion of the above steps, the California Registry will accept a participant's verified data into its emissions database.

A step-by-step description of the verification process is described in Section IV.14.9.

Core Verification Activities

The verification process is designed to ensure that there have been no material discrepancies of your reported entity-wide inventory. In order to ensure consistency in the application of verification, the California Registry provides all verifiers with a General Verification Protocol that is based on the guidance contained in this Protocol and any industry-specific protocol. The General Verification Protocol is a guidance document. However, since verifiers face potential financial liability for reports they have verified, it is ultimately at the verifier's discretion whether to verify your report.

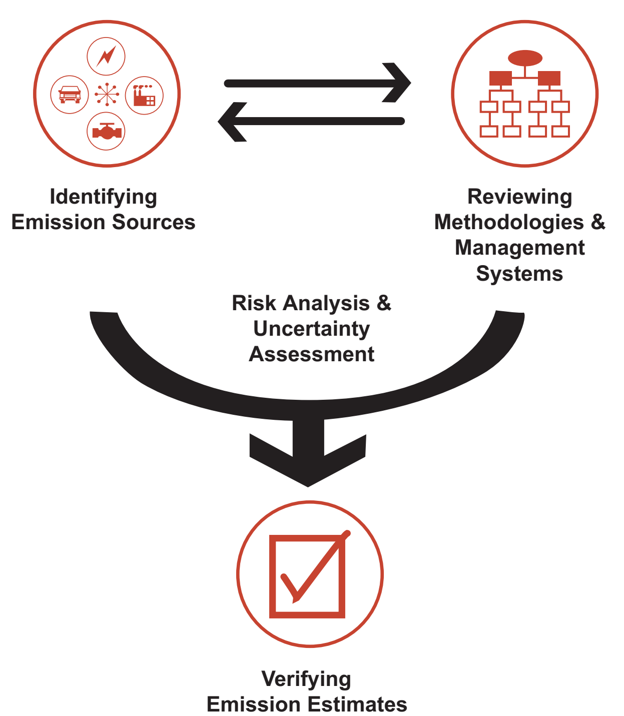
Once the verifier has completed the preparations for verification, including the kick-off meeting and the selection of a general approach to verification, the core verification activities can begin.

The core verification activities include three primary elements:

1. Identifying emissions sources;
2. Understanding management systems and estimation methods used; and
3. Verifying emissions estimates.

The core verification activities are fundamentally a risk assessment and data sampling effort aimed at ensuring that no significant sources are excluded and that the risk of error is assessed and addressed through appropriate sampling and review. The complete core verification process is illustrated in Figure IV.14.1.

Figure IV.14.1 Core Verification Process



IV.14.5 Professional Judgment

Approved verifiers must verify participants' annual GHG emissions reports against the California Registry's General Reporting Protocol using the process outlined in the General Verification Protocol. The California Registry asks verifiers to use their professional judgment when executing the verification activities described in the General Verification Protocol. The purpose of the verifier accreditation process is to ensure that verification firms demonstrate, through their staff's professional qualifications and experience, their ability to render sound professional judgments about GHG emissions reports.

Application of a verifier's professional judgment is expected in the following areas:

- Implementation of verification activities with appropriate rigor for the size and complexity of a participant's organization and with regard to the uncertainty of calculations associated with the participant's emissions sources;
- Review of the appropriateness of a participant's GHG emissions tracking and monitoring procedures, calculation methodologies, and management systems for providing information to the California Climate Action Registry;
- Evaluation of participant compliance with the California Registry's General Reporting Protocol;
- Assessment of methods used for estimating emissions from sources for which the General Reporting Protocol does not provide specific guidance, such as process and fugitive emissions, and indirect emissions from sources other than electricity, imported steam, and district heating and cooling; and
- Appraisal of assumptions, estimation methods, and emission factors that are selected as alternatives to those provided in the General Reporting Protocol.

The General Verification Protocol and training provided by the California Registry are intended to explain to the verifier the California Registry's guidelines and expectations and thus what types of professional judgments are appropriate for this program. In addition to these resources, verifiers and participants may contact the California Registry at any time for clarification of California Registry guidelines, expectations, and policies.

IV.14.6 Conflict of Interest

In order to ensure the credibility of the emissions data reported to the California Registry and its applicability under any future regulatory regime, it is critical that the verification process is completely independent from the influence of the participant submitting the emissions report. While conducting verification activities for California Registry participants, verifiers must work in a credible, independent, nondiscriminatory, and transparent manner, complying with applicable state and federal law and the California Registry's Conflict of Interest (COI) determination process.

Verification bodies must provide information to the accreditation body about their organizational relationships and internal structures for identifying potential conflicts of interest (organizational COI). Then, on an individual basis, the California Registry will review any pre-existing relationship between a verifier and participant and will assess the potential for conflict of interest (case-by-case COI) in conducting a verification. When the California Registry determines there is a low risk of COI, the participant and verifier can finalize negotiations of their contract. Following completion of a verification, the verifier must monitor their business relationships for the next year for situations that may create a COI (emerging COI) and notify the California Registry before entering into new business relationships with these participants.

This conflict of interest clause does not preclude a verifier from engaging in consulting services for other clients that participate in the California Registry for whom the verifier does not provide any verification activities.

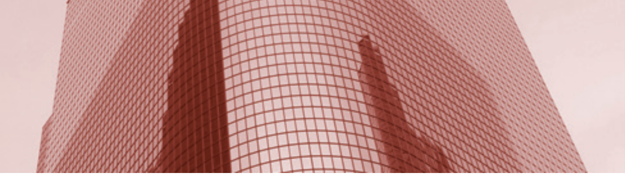
Verifiers must submit an updated COI form each year, even if they have verified previous years' emissions reports for a participant.

As an added protection, a verifier may provide verification services to a California Registry participant for, at most, six consecutive years. After a six-year period, the California Registry participant must engage a different verifier. The original verifier may not provide verification services to that participant for three years. This three-year hiatus begins with any lapse in providing annual verification services to a California Registry participant.

In the event that a verifier violates these conditions, the accreditation body, at its discretion, may disqualify an approved verifier for a period of up to five years.

IV.14.7 Reporting and Verification Deadlines

You must submit your GHG emissions report by June 30 of the year following the emissions year to the California Registry to initiate verification activities. Verification should be completed by October 31 of the year the report is submitted to the California Registry. In other words, a GHG emissions report for 2008 emissions should be submitted by June 30, 2009, and the verification process should be completed by October 31, 2009.



Participants who are not able to meet these deadlines must request a reporting or verification extension from the California Registry.

Reporting Deadline: June 30

Verification Deadline: October 31

IV.14.8 State Role in Verification

The California Registry's enabling legislation directed two state agencies, the Resources Agency and the Environmental Protection Agency, to provide technical guidance to the California Registry, including developing verification procedures. The State of California helps the California Registry to oversee verification activities. This includes randomly accompanying verifiers on site visits to evaluate the participant's GHG reporting program and the reasonableness of the participant's reported data. The State has worked through the California Energy Commission, the California Air Resources Board, and the California Department of Forestry and Fire Protection to conduct this oversight.

IV.14.9 Key Verification Steps

Verification consists of a number of procedural steps that must be taken to ensure that the obligations and responsibilities of both the verifier and participant are clear, as well as verification activities that ascertain the accuracy and completeness of an emissions report.

The following summary of the major steps of the verification process is provided as a reference.

1. **Participant Selects Verifier:** The participant may contact one or more State- or California Registry-approved verifiers to discuss verification activities. The participant selects a company to verify its GHG emissions results and begins to negotiate contract terms.
2. **Verifier Submits Case-Specific Notification of Verification Activities and Request for Evaluation of Conflict of Interest Form:** After a participant chooses a verifier, the verifier must submit a Notification of Verification Activities and Conflict of Interest Evaluation Form to the California Registry at a minimum of 10 business days prior to beginning verification activities. This is to establish the plan and scope of verification activities, and to ensure that the likelihood of a COI between parties is low or that risk of any conflict can be sufficiently mitigated by the verification body.
3. **California Registry Sends COI Determination to Verifier:** The California Registry reviews the Evaluation of COI Form and supporting information to determine the level of risk associated with the proposed participant/verifier relationship, and notifies the verifier of its determination.
4. **Verifier and Participant Finalize Contract:** When the California Registry provides a favorable COI determination between a participant and a verifier, verifiers may finalize their contract with a California Registry participant.
5. **Verifier Conducts Verification Activities:** The verifier follows the guidance in the General Verification Protocol to evaluate a participant's annual GHG emissions report.
6. **Verifier Prepares Verification Report and Verification Opinion for Participant:** The verifier prepares a detailed summary (Verification Report) of the verification activities for the participant. The verifier also prepares a Verification Opinion for the participant's review, and a Verification Activity Log.
7. **Verifier and Participant Discuss Verification Report and Opinion:** The verifier meets with the participant to discuss Verification Report and Opinion.
8. **Verifier Completes Verification Form and Verification Activity Log via CARROT:** Once authorized by a participant, the verifier completes the Verification Form and Log via CARROT.
9. **Participant Forwards Verification Opinion to the California Registry:** The participant emails the original Verification Opinion to the California Registry.
10. **California Registry Completes Reporting Process:** The California Registry reviews the Verification Opinion and Verification Activity Log and evaluates the participant's emissions report. Once accepted by the California Registry, a participant's aggregated entity-level emissions become available to the public via CARROT.

IV.14.10 Preparing for Verification

The pre-verification process involves several steps, including:

- Identifying accredited verification bodies on the California Registry's website;
- Executing a competitive bid process or awarding a sole source contract for verification services, or, if you are eligible, participating in batch verification (see Section IV.14.14) through the California Registry;
- Negotiating your contract with your selected verifier; and

- Assembling relevant materials needed by the verifier to verify your emissions data.

Use of California Registry-Approved Verifiers. You must choose your verifier from the list of accredited verification bodies maintained by the California Registry. Information about California Registry-approved verification bodies is provided on the California Registry website at www.climateregistry.org/serviceproviders.

Request for Bids for Verification Services

Options for Soliciting Bids. The California Registry recommends that those participants with complex GHG emissions reports solicit competitive bids for verification services from at least three verification bodies. If your organization has prepared a simpler GHG emissions report and does not seek, or is not eligible for, batch verification, you may wish to either secure competitive bids or to sole-source the verification contract in order to reduce costs and expedite the verification process.

Non-Disclosure Agreements. When preparing to send out a request for bids from verifiers, you should review the list of approved verification bodies and select some or all as prospective bidders. The California Registry recommends that you send the contact person from each prospective bidder a non-disclosure agreement prior to requesting bids or releasing potentially proprietary information.

The Request for Bids. In order to obtain the most competitive bids and ensure that you will receive the most effective verification services, your request for bids should include as much detailed information about your organization and its emissions report as possible.

The California Registry recommends that participants include the following information in their requests for bids from verification bodies:

1. The expected contract duration;
2. A general description of the participant's organization;
3. The geographic boundaries of the participant's report;
4. The number and locations of facilities and operations;
5. The GHGs reported in the participant's emissions report;
6. The emission source categories (and possibly emission sources) in the participant's report; and
7. A copy of the participant's emissions report from CARROT.

You should request bids and negotiate terms and conditions for a complete verification, including:

- A review of your management systems (required in year one and recommended at least every third year thereafter);
- A review of your underlying activity data;
- Confirmation of emissions estimates;
- A final Verification Report; and
- A Verification Opinion submitted to the California Registry.

The California Registry suggests that participants request Commercial and Technical Proposals from potential verifiers that include the following components:

Commercial Proposal

1. History and description of company
2. Explanation of core competencies
3. Proposed price for verification services
4. Proposed staff
5. Statement of verifier liability
6. Confidentiality policy
7. Duration of contract

Technical Proposal

1. Approach to preparing for verification
2. Approach for completing core verification activities
3. Approach for completing the verification process

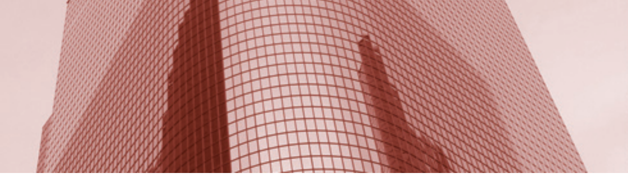
Negotiating a Contract with the Verifier

After you have selected a verifier from the approved verifiers that gave you bids, you should negotiate complete contract terms. This contract must be for direct services between the participant and an approved verifier. Contracts for verification services typically include the following components:

Scope of the Verification Process. This component of the contract will outline the exact geographic and organizational boundaries of the participant's emissions inventory to be examined. This should, but may not necessarily, match the boundaries used in the GHG emissions report to the California Registry. This scope will indicate whether California-only emissions are included or if both California and U.S. emissions are included. It will also include whether the participant has used the management control, equity share, or other method based on contractual relationships to determine organizational boundaries.

Confirmation of Approved Verifier Status. This is a simple statement that the verification body has been approved by the California Registry to verify emissions reports covering the scope listed above.

Verification Standard. Approved verifiers must verify participants' GHG emissions reports against the California Registry's General Reporting Protocol using the process




outlined in the General Verification Protocol. However, if a participant is reporting process or fugitive emissions, a separate industry-specific protocol may also be used and cited. Some participants may wish to use their GHG emissions report for additional purposes such as registering in another registry or participating in an emissions trading scheme or crediting program, etc., and thus may add additional standards for verification.

Non-Disclosure Terms. The verifier and the participant should agree in advance on methods for identifying and protecting proprietary and business confidential data that may be revealed during verification.

Site Access. The verifier and the participant should agree in advance to the time, place, and conditions of a verifier's site visits, if any are required.

Documentation and Data Requirements. The verifier and participant should agree on how and when the participant will provide emissions data to the verifier. The range of required documentation will largely be determined by the size and complexity of participant operations, and whether the participant has used the online calculation tools available through CARROT.

Period of Performance. The period of performance for verification services will typically be for three years, given that the verification process required by the California Registry is more streamlined in Year 2 and Year 3, if participant operations do not change. However, there may be instances where contracts are negotiated for a single year, pending renewal.

Performance Schedule. Participants and verifiers may wish to agree on a schedule to complete the verification process and for the verifier to deliver a Verification Report and Verification Opinion. Verification should be initiated in time to meet the October 31 verification deadline.

Payment Terms. Typical payment terms include total value, schedule of payments, and method of payment (e.g., electronic funds transfer).

Re-verification Terms. If the verifier identifies material discrepancies, the participant may choose to revise its GHG emissions report. At that time, the participant may ask the verifier to re-verify the report or seek verification from another provider. The verifier may not provide guidance, technical assistance or implementation work on the remediation of material misstatements, as this would be viewed as consulting services and result in a conflict of interest.

Liability. All verifiers are subject to the minimum liability associated with completing the verification per the terms of the verification contract. The participant may require and the verifier may agree to additional liability under this contract.

Contracts. The contract should identify technical leads for the participant and verifier, as well as responsible corporate officials of each party.

Verifier Requirement to Notify State of Verification

When the verifier submits the Notification of Verification Activities and COI Evaluation Form prior to beginning verification activities, the California Registry will notify the State of any and all planned verification activities at the time it makes its determination. This notification period is necessary to allow the State the opportunity to occasionally accompany verifiers on visits to participants' sites. The State observes, evaluates, and reports on the quality and consistency of verification activities. A verifier that does not provide proper notification to the California Registry at least 10 business days prior to beginning verification activities may be disqualified as an approved verifier.

Kick-off Meeting

After the verifier has notified the California Registry and the State of planned verification activities, verifiers should host a kick-off meeting with participants. Meetings can be conducted in person or by telephone. The agenda for that meeting should include:

1. Introduction of the verification team;
2. Review and confirmation of verification process and scope;
3. Transfer of background information and underlying activity data (see Table IV.14.1); and
4. Review and confirmation of the verification process schedule.

Based on the information provided in agenda items two and three, the verifier should determine the most effective, efficient, and credible detailed verification approach tailored to the particular characteristics of the participant.

IV.14.11 The Verification Cycle

While verification is required annually, in some instances it can be thought of as a three-year process. In Year 1, a verifier will need to form a detailed understanding of a participant's operations and consequential GHG emissions. Assuming that there have been no significant changes in the geographic and organizational boundaries of a participant's operations, a verifier is likely to have identified all emission sources and gained a sufficient understanding of the participant's GHG emissions management systems in Year 1 to streamline and

expedite the verification activities to focus on verifying emissions estimates in Year 2 and Year 3. To ensure data integrity, all of the core verification activities should be completed in Year 4.

Thus, the core verification activities each year will likely be as follows:

Year 1: **Identify Emission Sources, Review Management Systems, Verify Emissions Estimates**

Year 2: **Verify Emissions Estimates**

Year 3: **Verify Emissions Estimates**

Year 4: **Same as Year 1**

The California Registry assumes that verifiers will use their best professional judgment when conducting verification activities, and thus, will modify the suggested annual process described above as necessary. Each verifier is also required to complete a number of steps in their review, and to evaluate every participant against a number of criteria. These steps and criteria are listed in the Verification Activity Log, provided in the General Verification Protocol.

When you have specified a baseline, each year your verifier will need to identify changes to your direct emissions, review the cause of the changes, and assess if you have reached the baseline change threshold of 10%. The verifier will also determine if you have adjusted your baseline appropriately, if necessary.

As mentioned earlier, a verifier may provide verification services to a California Registry participant for, at most, six consecutive years (two verification cycles). After a six-year period, the California Registry participant must engage a different verifier and the original verifier may not provide verification services to that participant for three years.

IV.14.12 Online Reporting

If a participant chooses to use the built-in calculators and default emission factors in CARROT and the verifier's document review suggests that data have been collected properly and entered accurately, the verifier will not need to re-calculate the emissions, as the calculations will be automatic. Due to the time savings, this should result in a less expensive and expedited verification process.

IV.14.13 Documentation for Review

The documents that will need to be reviewed during verification will also vary depending on the nature of the emission sources contained in your GHG emissions report to the California Registry. Table IV.14.1 on the following page, provides a list of recommended documents to have ready to provide a verifier for conducting the verification process.

Table IV.14.1 Documents to be Reviewed During Verification Activities

Activity or Emissions Source	Documents
Identifying Emission Sources	
Emission Source Inventory	Facility inventory
	Emission source inventory Stationary source inventory Mobile source inventory Fuel inventory
Understanding Management Systems and Methodologies	
Responsibilities for Implementing GHG Management Plan	Organization chart, greenhouse gas management plan, documentation and retention plan
Training	Training manual, procedures manual, consultant qualification statement
Methodologies	Protocols used (if in addition to the California Registry's General Reporting Protocol)
Verifying Emission Estimates	
Indirect Emissions from Electricity Use	Monthly electric utility bills, emission factors (if not default)
Direct Emissions from Mobile Combustion	Fuel purchase records, fuel in stock, vehicle miles traveled, inventory of vehicles, emission factors (if not default)
Direct Emissions from Stationary Combustion	Monthly utility bills, fuel purchase records, CEMs data, inventory of stationary combustion facilities, emission factors (if not default)
Indirect Emissions from Cogeneration	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Indirect Emissions from Imported Steam	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Indirect Emissions from District Cooling	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Direct Emissions from Manufacturing Processes	Raw material inputs, production output, calculation methodology, emission factors
Refrigeration Systems	Refrigerant purchase records, refrigerant sales records, calculation methodology, emission factors
Landfills	Waste in place data, waste landfilled, calculation methodology, emission factors
Coal Mines	Coal production data submitted to EIA, quarterly MSHA reports, calculation methodology, emission factors
Natural Gas Pipelines	Gas throughput data, calculation methodology, emission factors
Electric Transmission and Distribution	Sulfur hexafluoride purchase records, calculation methodology, emission factors

IV.14.14 Batch Verification

In an effort to minimize the transaction costs of verification for small organizations with relatively simple emissions, the California Registry will contract with an approved verifier to undertake the verification work for interested participants with limited GHG emissions. The California Registry calls this batch verification. Emissions reports verified under batch verification must meet the same standards as non-batch reports. Eligible participants include those with:

- Less than 500 metric tons of CO_2e emissions per year;
- No significant process or fugitive emissions (de minimis emissions in these categories are allowed);
- Indirect emissions from purchased electricity at no more than four sites;
- Direct emissions from no more than five vehicles; and
- Direct emissions from stationary combustion at no more than one site.

Upon the recommendation of the batch verifier, the California Registry reserves the right to deem a participant's GHG emissions inventory too complex for batch verification. The California Registry also reserves the right to grant batch verification eligibility on a case-by-case basis.

Batch Verification Process Overview

The following is a summary of the steps of the batch verification process.

Participants interested in batch verification will notify the California Registry. After confirming the participant's eligibility, the California Registry will keep track of interested participants until a sufficient number have reported their emissions in CARROT and submitted the data for verification.

Each year, the California Registry will solicit competitive bids for batch verification services from at least three approved verifiers. On behalf of batch participants, the California Registry will select one verifier to perform all eligible verifications for that calendar year of emissions.

1. **Batch Verifier & Batch Participants Sign Contracts**: Each participant signs a standardized contract with the verifier. Any participant requiring non-standard contract language cannot participate in batch verification.
2. **Batch Verifier Receives Documentation:** After the entities participating in batch verification have completed their reports, the California Registry will collect the necessary supporting documentation from the participants and forward it to the verifier. Batch verification will not require a site visit, but will consist of document review and telephone interviews.
3. **Batch Verifier Conducts Verification Activities:** The verifier will follow the guidance in the General Verification Protocol to evaluate a participant's GHG emissions report. The verifier will contact each participant to understand their operations.
4. **Batch Verifier Provides Verification Report and Opinion to Participant:** The verifier prepares and discusses a summary of the verification activities with the participant (Verification Report). The verifier also provides the Verification Opinion to the participant. Once authorized by a participant, the verifier completes the Verification Form and Activity Log via CARROT.

The participant then emails the Verification Opinion to the California Registry at help@climateregistry.org.

The California Registry will review the Verification Opinion and Verification Activity Log and evaluate the participant's emissions report. Once accepted by the California Registry, a participant's aggregated entity-level emissions become available to the public via CARROT.

IV.14.15 Verification Report and Opinion

The verifier will prepare a detailed Verification Report for each emissions report. The Verification Report is a confidential document that is shared between a verifier and a participant—it is not available to the California Registry or the public unless a participant chooses to share it, or it is specifically requested by the California Registry.

Verification Report

The Verification Report should include the following elements:

- The scope of the verification process undertaken;
- The standard used to verify emissions (this is the California Registry's General Reporting Protocol, but may also include other protocols or methodologies for those sources for which the California Registry has yet to provide detailed guidance);
- A description of the verification activities, based on the size and complexity of the participant's operations;
- A list of emissions sources identified;
- A description of the sampling techniques and risk assessment methodologies employed for each source;
- An evaluation of the participant's emissions report compliance with the California Registry's General Reporting Protocol;
- A comparison of the participant's overall emission estimates with the verifier's overall emission estimates;
- A list of material discrepancies, if any;

- A list of immaterial discrepancies, if any; and
- A general conclusion to be reflected in the Verification Opinion forwarded to the California Registry.

A participating organization should be provided up to 30 days to review and comment on the Verification Report. At the end of that review, the verifier and the participating organization should hold a meeting to discuss the nature of any material or immaterial discrepancies.

Verification Opinion

The Verification Opinion is a simple confirmation of the verification activities and outcomes for all stakeholders (participants, verifiers, the California Registry, and the public). The Verification Opinion must also follow the same internal review process as the Verification Report, and consequently must be reviewed and signed by the verification firm and submitted by the participating organization.

Exit Meeting

Verifiers should prepare a brief summary presentation of their verification findings for the participant's key personnel. At the exit meeting verifiers and participants might exchange lessons learned about the verification process and share thoughts for improving the verification process in the future. Verifiers and participants may wish to consider joint feedback to the California Registry.

The goals of this meeting should be:

- Acceptance of the Verification Report and Opinion (unless material discrepancies exist and can be remediated, in which case the verification contract may need to be revised, and a re-verification scheduled). If the participant does not wish to retain the verifier for the re-verification process, the verifier shall turn over all relevant documentation to the participant within 30 days.
- Authorization for the verifier to complete the Verification Form in CARROT.

IV.14.16 Submitting a Verified Emissions Report to the California Registry

Once a participant authorizes the Verification Opinion, the verifier must complete the electronic Verification Form in CARROT and send the original Verification Opinion to the participant. The participant must forward the original copy of the Verification Opinion to the California Registry.

Once the electronic Verification Form is completed and the California Registry receives a hardcopy of the Verification Opinion, the participant's report will be reviewed and formally accepted into the California Registry database, and the annual verification process will be completed.

Participants are not required to submit their Verification Opinions to the California Registry for the first two years of their participation. However, a participant's emissions data will not be considered accepted by the California Registry unless the California Registry receives a Verification Opinion indicating a "verified without qualification" assessment.

IV.14.17 Record Keeping and Retention

You should maintain any relevant records from which emissions results have been calculated. Such records may include, but not be limited to, utility bills, fuel consumption records, emissions data, process data and schedules, and past reports. Although it is not possible to predict what any future regulatory regime may require regarding record keeping and retention, it is inadvisable for you to dispose of relevant records immediately after filing emissions reports. This would hinder any future verification or review activities, placing you at a disadvantage in case of some need to re-estimate the emissions results. In addition, your baseline inventory data is the key to determining temporal trends in GHG emissions.

IV.14.18 Correcting or Revising Your GHG Emissions Report

After you have submitted your verified GHG emissions report to the California Registry, you will still be able to make corrections if you have determined an error in your report, have identified new emissions sources, or would like to utilize more thorough calculation methodologies to estimate your emissions. You should note that the California Registry's reporting system is designed to retain all original reports and records it receives as archives, even after a GHG emissions report has been corrected or updated.

Should you update your GHG emissions report, the updated portion will need to be re-verified by a California Registry-approved verifier, following the process described in this chapter. Note that if the specific changes you have made to your report influence or affect the estimations of other elements of your report, you will again need to have the verifier review and verify all relevant sections of your GHG emissions report. Where your overall corrections result in an insignificant change in emissions from your previous GHG emissions report, verification should require only verifying your emissions estimates. Once a revision is initiated in CARROT, the information is not publicly available until all additions to the report are verified.

IV.14.19 Dispute Resolution

There may be instances where a verifier and a participant cannot agree on identification of material discrepancies and/or the findings of the Verification Opinion. In such instances, both parties can request the Dispute Resolution Committee, composed of qualified representatives from California state agencies, the California Registry, and one non-voting verifier, who serves pro bono on an annual, rotating basis. The participant and the verifier will each pay a filing fee equal to 5% of the participant's annual California Registry membership fee to submit the matter to the Dispute Resolution Committee.

The Dispute Resolution Committee will interview the participant and the verifier, review the area of dispute and reach a unanimous, binding decision concerning verifiability. The California Registry will notify the verifier and California Registry participant of the Committee's decision. Thus, as part of contract negotiations, each California Registry participant and verifier will need to sign a form agreeing to this Dispute Resolution policy.

IV.14.20 Key Verification Questions

Verification Deadlines: What is the deadline for completing the verification process?

Emissions should be reported to the California Registry no later than June 30 following the emissions year. Verification should be completed by October 31 following the emissions year. For instance, 2008 emissions should be reported by June 30, 2009 and verified by October 31, 2009.

Costs: What will it cost to have my GHG emissions report verified?

Because verifiers will review GHG emissions reports with more scrutiny every fourth year (barring significant changes to your geographic or organizational boundaries), costs associated with verification are likely to be higher in the first year than in years two or three of the reporting process. In order to obtain an estimate for verification, you will need to convey information about your industrial sector, organization size (annual revenue and number of employees), number of facilities, estimated number and type of direct emissions sources, types of indirect emissions sources (e.g., electricity from a utility or electricity or heat from co-generation), the types of gases you are reporting, and the methodologies you are using to estimate and report your emissions (e.g., CARROT).

You may contact the California Registry for information about the costs associated with verifying your GHG emissions report.

In addition, you may contact California Registry-approved verifiers listed on the California Registry's website at www.climateregistry.org for information about the estimated costs associated with verification.

Batch Verification: What is it? How does it work? How will it affect bidding, contracting, and the overall verification process?

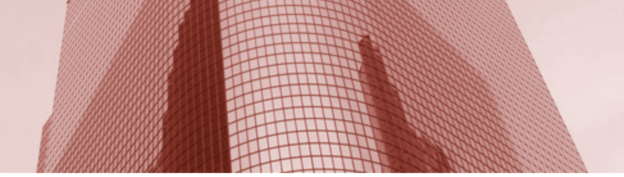
In an effort to minimize transaction costs, eligible California Registry participants may request to participate in batch verification with similar organizations through the California Registry. Eligible participants have relatively simple GHG emission sources and no more than 500 tons of CO_2e from only indirect emissions from electricity consumption at four or fewer sites, direct emissions from stationary combustion at a single site, and/or direct emissions from five or less vehicles. In that situation, bidding, contract negotiations, and the kick-off meeting will take place between the verifier and the California Registry. Standard terms and conditions are expected to apply for all contract elements. The California Registry will initiate the procurement process for batch verification.

Verification and Remediation: What if my GHG emissions report is not verified?

At the completion of the verification process, the verifier will prepare a Verification Report and forward it to the responsible official representing the California Registry participant. (The responsible official includes anyone authorized by the participant to approve the GHG emissions report for submission to the California Registry and will typically be a corporate official or the technical manager of the verification contract.)

If the verifier identifies material discrepancies that prevent a favorable Verification Opinion, those material misstatements should be listed and described in the Verification Report. If possible, the participant may correct those material discrepancies and resubmit the emissions report for verification within a reasonable amount of time. The participant may hire technical assistance to correct material discrepancies but the verifier may not provide such technical assistance as it would create a conflict of interest.

If the participant is unable to correct the material discrepancies, the California Registry will retain the participant's data in the California Registry database for up to two years pending verification. Participants who have submitted a report and undergone verification as part of a "learning by doing" process may wish to retain a pending status for their emissions report for up to two years while the report is enhanced. After that time, the data will be deleted from CARROT. The participant may re-enter the data at a later date with the same conditions.



Verification Report, Verification Opinion, and Verification Activity Log: What are these documents and how are they different?

The Verification Report is a detailed report that a verifier prepares for a participant. The report should describe the scope of the verification process, standards used, emissions sources identified, sampling techniques, and evaluation of the participant's compliance with the General Reporting Protocol, and list material and immaterial discrepancies, if any. The Verification Report is a confidential document between a verifier and participant, and is not shared with the California Registry or the public.

The Verification Opinion is a brief, one-page summary of a verifier's findings that simply states if a participant's emissions report is verifiable or not. The Verification Opinion is submitted to the participant and then to the California Registry. A majority of the contents of the Verification Opinion will be available to the public.

The Verification Activity Log is a form that the verifier must complete that asks them to demonstrate consistency in their professional judgments. The form asks them to respond to a series of yes and no questions, and to provide the dates they have performed verification activities. This information is submitted by the verifier to the California Registry via CARROT, and is not shared with the public.

Confidentiality: Are the results of the verification kept confidential? Are emissions data kept confidential?

The California Registry will make public the Verification Opinion as well as the identity of your verifier, but not your Verification Report. All aggregated entity-level emissions data and metrics reported to the California Registry will be available to the public. However, the California Registry intends to keep confidential all reported emissions, activity data, methodologies, and emissions factors with a higher granularity (at facility, project or source levels). Confidential information will only be accessible to the participant, the California Registry, and the verifier, unless the participant allows others access to such information or wishes to have it available to the public.

General Verification Protocol Revision Policy: Will the General Verification Protocol change over time? How can participants provide feedback to the California Registry?

The California Registry expects to regularly review, revise, update, and augment the General Verification Protocol. The California Registry invites all parties, verifiers, California Registry participants, California State agencies, and the public to provide insights and experiences that will help improve the General Verification Protocol. Anyone with suggestions or concerns is encouraged to contact the California Registry at any time.

Stakeholders will also be able to present suggestions directly to the California Registry's Board of Directors for consideration at their meetings. All suggestions and requests for modifications must be made by utilizing the "Protocol Comment Form" available on the California Registry's website at www.climateregistry.org/protocols.

Appendix A Glossary

Anthropogenic Emissions

GHG emissions that are a direct result of human activities or are the result of natural processes that have been affected by human activities.

Barrel (bbl)

Commonly used to measure quantities of various petroleum products, a volumetric measure for liquids equal to 42 U.S. gallons at 60 degrees Fahrenheit.

Baseline

For the purposes of this Protocol, a datum against which to measure GHG emissions performance or change over time, usually annual emissions in a selected base year.

Base year

The first year in which GHG emissions are reported.

Batch Verification

Simultaneous verification process arranged by the California Registry for multiple participants with simple GHG emissions (typically only indirect emissions from electricity consumption and direct emissions from stationary combustion at a single site and/or direct emissions from a small number of vehicles).

Biogenic Emissions

CO_2 emissions produced from combusting a variety of biofuels, such as biodiesel, ethanol, wood, wood waste and landfill gas.

British Thermal Unit (BTU)

The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Carbon Dioxide (CO_2)

The most common of the six primary GHGs, consisting of a single carbon atom and two oxygen atoms, and providing the reference point for the GWP of other gases. (Thus, the GWP of CO_2 is equal to one.)

CO_2 equivalent (CO_2e)

A measure for comparing carbon dioxide with other GHGs (which generally have a higher global warming potential (GWP)), based on the amount of those other gases multiplied by the appropriate GWP factor; commonly expressed as metric tons of carbon dioxide equivalents ($MTCO_2e$). CO_2e is calculated by multiplying the metric tons of a gas by the appropriate GWP.

Carbon Intensity

The relative amount of carbon emitted per unit of energy or fuels consumed.

Co-Generation

The generation of two forms of energy such as heat and electricity from the same process with the purpose of utilizing or selling both simultaneously.

Datum

A reference or starting point.

De Minimis

For the purposes of this Protocol, the 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 Emissions

For the purposes of this Protocol, emissions from applicable sources that are owned or controlled by the reporting organization.

Emission Factor

A unique value for determining an amount of a GHG emitted for a given quantity of activity data (e.g., million metric tons of carbon dioxide emitted per barrel of fossil fuel).

Equity Share

According to the calculated share.

Fugitive Emissions

Emissions that are not physically controlled but result from the intentional or unintentional release of GHGs. They commonly arise from the production, processing, transmission, storage and use of fuels or other chemicals, often through joints, seals, packing, gaskets, etc. Examples include HFCs from refrigeration leaks, SF_6 from electrical power distributors, and CH_4 from solid waste landfills.

Global Warming Potential (GWP)

The ratio of radiative forcing that would result from the emission of one kilogram of a GHG to that from the emission of one kilogram of carbon dioxide over a fixed period of time.

Greenhouse Gases (GHGs)

For the purposes of the California Registry, GHGs are the six gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Higher Heating Value (HHV)

The amount of heat released from the complete combustion of a fuel including water vapor produced in the process.

Hydrocarbons

Chemical compounds containing only carbon and hydrogen, including fossil fuels and a variety of major air pollutants.

Hydrofluorocarbons (HFCs)

One of the six primary GHGs primarily used as refrigerants, consists of a class of gases containing hydrogen, fluorine, and carbon, and possessing a range of high and very high GWP values from 120 to 12,000.

Indirect Emissions

Emissions that occur because of a participant's actions, but are produced by sources owned or controlled by another entity.

Intergovernmental Panel on Climate Change (IPCC)

An organization established jointly by the United Nations Environment Programme and the World Meteorological Organization in 1988 to assess information in the scientific and technical literature related to all significant components of the issue of climate change, and providing technical analysis of the science of climate change as well as guidance on the quantification of GHG emissions.

Joule

A measure of energy, representing the energy needed to push with a force of one Newton for one meter.

Kilowatt Hour (kWh)

The electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A Watt is the unit of electrical power equal to one ampere under a pressure of one volt, or 1/746 horsepower.)

Leakage

A situation where emissions shift from one location to another resulting in a direct increase in emissions.

Lower Heating Value (LHV)

The amount of heat released from the complete combustion of a fuel after netting out the heat that is released with the water vapor produced in the process.

Management Control

The ability of an entity to govern the operating policies of another entity or facility so as to obtain benefits from its activities.

Material

Any emission of GHG that is not de minimis in quantity.

Material Discrepancy

With respect to verifying an entity's emissions inventory, a material discrepancy occurs when a difference in reported emissions between an entity and a verifier exceeds 5% of the reported emissions. A difference is immaterial if it is less than 5% of reported emissions.

Member

An entity that is preparing its annual GHG emissions report, but does not have a current verified emissions report with the California Registry.

Methane (CH_4)

One of the six primary GHGs, consisting of a single carbon atom and four hydrogen atoms, possessing a GWP of 21, and produced through the anaerobic decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion.

Metric Ton

Common international measurement for the quantity of GHG emissions, equivalent to about 2,204.6 pounds or 1.1 short tons.

Mobile Combustion

Burning of fuels by transportation devices such as cars, trucks, airplanes, vessels, etc.

Nitrous Oxide (N_2O)

One of the six primary GHGs, consisting of two nitrogen atoms and a single oxygen atom, possessing a GWP of 310, and typically generated as a result of soil cultivation practices, particularly the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.

Perfluorocarbons (PFCs)

One of the six primary GHGs, consists of a class of gases containing carbon and fluorine (represented by the chemical formula CNF(2N+2)), originally introduced as alternatives to ozone depleting substances and typically emitted as by-products of industrial and manufacturing processes, and possessing GWPs ranging from 5,700 to 11,900.

Process Emissions

Emissions from physical or chemical processing rather than from fuel combustion. Examples include CO_2 emissions from cement manufacturing and PFC emissions from aluminum smelting.

Project Baseline

Datum against which to measure GHG emissions performance of a specific emissions reduction project over time, usually annual emissions measured from a base year.

Outsourcing

The contracting out of activities to other businesses.

Significance Threshold

Significance, in the context of the California Registry, is defined as including all sources that are not de minimis. For the purposes of the California Registry, the significance threshold is set at 95%.

Stationary Combustion

Burning of fuels to generate electricity, steam, or heat.

Short Ton

Common measurement for a ton in the U.S. and equivalent to 2,000 pounds or about 0.907 metric tons.

Sulfur Hexafluoride (SF_6)

One of the six primary GHGs, consisting of a single sulfur atom and six fluoride atoms, possessing a very high GWP of 23,900, and primarily used in electrical transmission and distribution systems.

Therm

A measure of one hundred thousand (10^5) Btu.

Verification

For the purposes of this Protocol, the method used to ensure that a given participant's GHG emissions inventory (either the baseline or annual result) has met a minimum quality standard and complied with an appropriate set of California Registry-approved procedures and protocols for submitting emissions inventory information.

Verification Body

For the purposes of this Protocol, an organization or company that is considered California Registry-approved. This applies to currently approved verification bodies, verification bodies approved by the State of California and verification bodies that are accredited to the international standard ISO 14065:2007 to perform GHG verification activities.

Verified Member

A California Registry participant that has a current verified annual emissions report accepted by the California Registry; also known as a *Climate Action Leader*.

Verifier

For the purposes of this Protocol, an individual that is staff or a subcontractor to a California Registry-approved verification body and is qualified to provide verification services for California Registry participants. All verifiers shall complete California Registry training and shall be identified on the designated staff form submitted to the California Registry.

Appendix B Common Conversion Factors

Energy		
1 quadrillion Btu	=	1.0551 x 10^{18} joules
	=	1.0551 exajoules
	=	10^{9} MMBtu
1 MMBtu (million Btu)	=	1.0551 x 10^{12} joules
	=	1.0551 x 10^{-6} exajoules
	=	10 Therm
1 joule	=	947.9 x 10^{-21} quadrillion Btu
1 exajoule	=	10^{18} joules
	=	0.9479 quadrillion Btu
1 GJ (gigajoule)	=	947,817 Btu
	=	277.8 kilowatt hours (kWh)
	=	0.2778 Megawatt hours (MWh)
1 Therm	=	10^{5} Btu
Mass		
1 short ton (U.S. ton)	=	2,000 pounds (lbs)
	=	0.9072 metric tons
	=	9.072 x 10^{4} grams
1 kilogram	=	2.20462 pounds (lbs)
1 metric ton	=	1.1023 short tons
	=	1.1023 tons (U.S.)
	=	2,204.62 pounds (lbs)
	=	1,000 kg
	=	10^{-3} kilotons
	=	10^{-6} megatons
Volume		
1 cubic centimeter	=	3.531 x 10^{-5} cubic feet
1 cubic meter (m^3)	=	35.3115 ft^3 (cubic feet)
	=	1,000 liters
	=	264.2 U.S. gallons
	=	6.29 barrels
	=	1.308 yd^3 (cubic yards)
1 barrel	=	42 gallons
	=	5.6139 ft^3 (cubic feet)
	=	0.15898 m^3
	=	158.98 liters

Area

1 acre	=	0.40468724 hectare (ha)
	=	4,047 m^2
1 hectare (ha)	=	35.3115 ft^3 (cubic feet)
	=	10,000 m^2
	=	2.47 acres

Distance

1 kilometer	=	0.6214 miles

Density

1,000 cubic feet of methane (CH_4)	=	42.28 pounds
	=	1,000 cubic feet carbon dioxide (CO_2)
	=	115.97 pounds
1 metric ton natural gas liquids	=	11.6 barrels
1 metric ton unfinished oils	=	7.46 barrels
1 metric ton alcohol	=	7.94 barrels
1 metric ton liquefied petroleum gas	=	11.6 barrels
1 metric ton aviation gasoline	=	8.9 barrels
1 metric ton naphtha jet fuel	=	8.27 barrels
1 metric ton kerosene jet fuel	=	7.93 barrels
1 metric ton motor gasoline	=	8.53 barrels
1 metric ton kerosene	=	7.73 barrels
1 metric ton naphtha	=	8.22 barrels
1 metric ton distillate	=	7.46 barrels
1 metric ton residual oil	=	6.66 barrels
1 metric ton lubricants	=	7.06 barrels
1 metric ton bitumen	=	6.06 barrels
1 metric ton waxes	=	7.87 barrels
1 metric ton petroleum coke	=	5.51 barrels
1 metric ton petrochemical feedstocks	=	7.46 barrels
1 metric ton special naphtha	=	8.53 barrels
1 metric ton miscellaneous products	=	8.00 barrels

Metric Prefixes

Abbreviation	Prefix	Multiple
k	kilo-	10^3 or 1,000
M	mega-	10^6 or 1,000,000
G	giga-	10^9 or 1,000,000,000
T	tera-	10^{12} or 1,000,000,000,000
P	peta-	10^{15} or 1,000,000,000,000,000

Appendix C Calculation References

Converting to CO_2 Equivalent

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 (CO_2e). To do this, multiply the emissions in units of mass by the GHGs global warming potential (GWP).

Global warming potentials were developed by the Intergovernmental Panel on Climate Change (IPCC) to quantify the globally averaged relative radiative forcing effects of a given GHG, using carbon dioxide as the reference gas. In 1996, the IPCC published a set of GWPs for the most commonly measured greenhouse gases in its Second Assessment Report (SAR). In 2001, the IPCC published its Third Assessment Report (TAR), which adjusted the GWPs to reflect new information on atmospheric lifetimes and an improved calculation of the radiative forcing of carbon dioxide. However, SAR GWPs are still used by international convention and the U.S. to maintain the value of the carbon dioxide "currency". To maintain consistency with international practice, the California Registry requires participants to use GWPs from the SAR for calculating their emissions inventory.

Table C.1 lists the 100-year GWPs from SAR and TAR. The equation above provides the basic calculation required to determine CO_2e from the total mass of a given GHG using the GWPs published by the IPCC.

Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e = Metric Tons of GHG x GWP

Table C.1 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: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003 (April 2005).

Emission Factors for Electricity Use

Table C.2 Carbon Dioxide, Methane and Nitrous Oxide Electricity Emission Factors by eGRID Subregion

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: Reporters calculating historical data for calendar years 1990-2007 should use the electricity emission factors in Appendix E.

Emission Factors for Mobile Combustion

Table C.3 Carbon Dioxide Emission Factors for Transport Fuels

Fuel	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor
	kg C/MMBtu	MMBtu/barrel		kg CO_2/gallon
Aviation Gasoline	18.87	5.048	1.00	8.32
Biodiesel (B100)* +	NA	NA	1.00	9.46
Crude Oil	20.33	5.80	1.00	10.29
Diesel	19.95	5.825	1.00	10.15
Ethanol (E100)* +	17.99	3.539	1.00	5.56
Jet Fuel (Jet A or A-1)	19.33	5.670	1.00	9.57
Kerosene	19.72	5.670	1.00	9.76
Liquefied Natural Gas (LNG)+	NA	NA	1.00	4.46
Liquefied Petroleum Gas (LPG)+	17.23	3.849	1.00	5.79
Ethane	16.25	2.916	1.00	4.14
Isobutane	17.75	4.162	1.00	6.45
n-Butane	17.72	4.328	1.00	6.70
Propane	17.20	3.824	1.00	5.74
Methanol	NA	NA	1.00	4.10
Motor Gasoline	19.33	5.218	1.00	8.81
Residual Fuel Oil (#5, 6)	21.49	6.287	1.00	11.80
	kg C/MMBtu	Btu/standard cubic foot		kg CO_2/therm
Compressed Natural Gas (CNG)+	14.47	1027	1.00	5.31

* CO_2 emissions from biodiesel and ethanol combustion are considered biogenic and should not be reported as a direct mobile combustion emission (see Chapter 7). These biogenic CO_2 emissions may be reported optionally.

Note: CO_2 emission factors are calculated using the molar mass ratio of carbon dioxide to carbon (CO_2/C) of 44/12. Heat content factors are based on higher heating values (HHV). NA = data not available. A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006).

Source: U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 2.1, Tables A-31, A-34, A-36, A-39, except those marked + (from EPA Climate Leaders Mobile Combustion Guidance). Methanol emission factor is calculated from the properties of the pure compounds.

Table C.4 Methane and Nitrous Oxide Emission Factors for Highway Vehicles by Model Year

Vehicle Types/Model Years	N_2O (g/mile)	CH_4 (g/mile)
Gasoline Passenger Cars		
Model Years 1984-1993	0.0647	0.0704
Model Year 1994	0.0560	0.0531
Model Year 1995	0.0473	0.0358
Model Year 1996	0.0426	0.0272
Model Year 1997	0.0422	0.0268
Model Year 1998	0.0393	0.0249
Model Year 1999	0.0337	0.0216
Model Year 2000	0.0273	0.0178
Model Year 2001	0.0158	0.0110
Model Year 2002	0.0153	0.0107
Model Year 2003	0.0135	0.0114
Model Year 2004	0.0083	0.0145
Model Year 2005 - Present	0.0079	0.0147
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
Model Years 1987-1993	0.1035	0.0813
Model Year 1994	0.0982	0.0646
Model Year 1995	0.0908	0.0517
Model Year 1996	0.0871	0.0452
Model Year 1997	0.0871	0.0452
Model Year 1998	0.0728	0.0391
Model Year 1999	0.0564	0.0321
Model Year 2000	0.0621	0.0346
Model Year 2001	0.0164	0.0151
Model Year 2002	0.0228	0.0178
Model Year 2003	0.0114	0.0155
Model Year 2004	0.0132	0.0152
Model Year 2005 - Present	0.0101	0.0157

Table C.4 Methane and Nitrous Oxide Emission Factors for Highway Vehicles by Model Year (continued)

Vehicle Types/Model Years	N_2O (g/mile)	CH_4 (g/mile)
Gasoline Heavy-Duty Vehicles		
Model Years 1985-1986	0.0515	0.4090
Model Year 1987	0.0849	0.3675
Model Years 1988-1989	0.0933	0.3492
Model Years 1990-1995	0.1142	0.3246
Model Year 1996	0.1680	0.1278
Model Year 1997	0.1726	0.0924
Model Year 1998	0.1693	0.0641
Model Year 1999	0.1435	0.0578
Model Year 2000	0.1092	0.0493
Model Year 2001	0.1235	0.0528
Model Year 2002	0.1307	0.0546
Model Year 2003	0.1240	0.0533
Model Year 2004	0.0285	0.0341
Model Year 2005 - Present	0.0177	0.0326
Diesel Passenger Cars		
Model Years 1960-1982	0.0012	0.0006
Model Years 1983 - Present	0.0010	0.0005
Diesel Light Trucks		
Model Years 1960-1982	0.0017	0.0011
Model Years 1983-1995	0.0014	0.0009
Model Years 1996 - Present	0.0015	0.0010
Diesel Heavy-Duty Vehicles		
All Model Years	0.0048	0.0051

Source: Gasoline vehicle factors from EPA Climate Leaders, Mobile Combustion Guidance, (2008) based on U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007). Diesel vehicle factors based on U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-98.

Table C.5 Methane and Nitrous Oxide Emission Factors for Alternative Fuel Vehicles

Vehicle Type	N_2O (g/mile)	CH_4 (g/mile)
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Heavy Duty Vehicles		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Biodiesel*	0.050	0.060
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197

Source: U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-100, except biodiesel.

* Biodiesel emission factor derived from California Energy Commission, Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (Draft: December 2001), Table 2-20.

Table C.6 Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles

Vehicle Type/Fuel Type	N_2O (g/gallon)	CH_4 (g/gallon)
Ships & Boats		
Residual Fuel Oil	0.30	0.86
Diesel Fuel	0.26	0.74
Gasoline	0.22	0.64
Locomotives		
Diesel Fuel	0.26	0.80
Agricultural Equipment		
Gasoline	0.22	1.26
Diesel Fuel	0.26	1.44
Construction		
Gasoline	0.22	0.50
Diesel Fuel	0.26	0.58
Other Non-Highway		
Snowmobiles (Gasoline)	0.22	0.50
Other Recreational (Gasoline)	0.22	0.50
Other Small Utility (Gasoline)	0.22	0.50
Other Large Utility (Gasoline)	0.22	0.50
Other Large Utility (Diesel)	0.26	0.58
Aircraft		
Jet Fuel	0.31	0.27
Aviation Gasoline	0.11	7.04
All Non-Highway/Construction Vehicles		
Butane*	0.41	0.09
Propane*	0.41	0.09

Source: U.S. EPA, Climate Leaders, Mobile Combustion Guidance (2008) based on U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-101, except butane and propane.

* Butane and propane emission factors based on stationary combustion emission factors for these fuels from U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000 (2002).

Emission Factors for Stationary Combustion

Table C.7 Carbon Dioxide Emission Factors for Stationary Combustion

Fuel Type	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor	CO_2 Emission Factor
Coal and Coke	kg C/ MMBtu	MMBtu/ short ton		kg CO_2/ metric ton	kg CO_2/MMBtu
Anthracite	28.26	25.09	1.00	2,865.77	103.62
Bituminous	25.49	24.93	1.00	2,568.39	93.46
Sub-bituminous	26.48	17.25	1.00	1,846.19	97.09
Lignite	26.30	14.21	1.00	1,510.49	96.43
Residential/Commercial	26.00	22.05	1.00	2,317.13	95.33
Industrial Coking	25.56	26.27	1.00	2,713.87	93.72
Other Industrial	25.63	22.05	1.00	2,284.16	93.98
Electric Power	25.76	19.95	1.00	2,077.10	94.45
Coke	31.00	24.80	1.00	3,107.29	113.67
Petroleum Products (Gaseous)	kg C/ MMBtu	Btu/ standard cubic foot		kg CO_2/ standard cubic foot	kg CO_2/MMBtu
Natural Gas (weighted U.S. average)	14.47	1,029	1.00	0.0546	53.06
Acetylene (C_2H_2)	19.48	1,476	1.00	.1043	71.42
Petroleum Products (Liquid)	kg C/ MMBtu	MMBtu/ barrel		kg CO_2/gallon	kg CO_2/MMBtu
Asphalt & Road Oil	20.62	6.636	1.00	11.95	75.61
Aviation Gasoline	18.87	5.048	1.00	8.32	69.19
Distillate Fuel Oil (#1,2&4)	19.95	5.825	1.00	10.15	73.15
Jet Fuel	19.33	5.670	1.00	9.57	70.88
Kerosene	19.72	5.670	1.00	9.76	72.31
LPG (average for fuel use)	17.23	3.849	1.00	5.79	63.16
Propane	17.20	3.824	1.00	5.74	63.07
Ethane	16.25	2.916	1.00	4.14	59.58
Isobutane	17.75	4.162	1.00	6.45	65.08
n-Butane	17.72	4.328	1.00	6.70	64.97
Lubricants	20.24	6.065	1.00	10.72	74.21
Motor Gasoline	19.33	5.218	1.00	8.81	70.88
Residual Fuel Oil (#5 & 6)	21.49	6.287	1.00	11.80	78.80
Crude Oil	20.33	5.800	1.00	10.29	74.54
Naphtha (<401 deg. F)	18.14	5.248	1.00	8.31	66.51
Natural Gasoline	18.24	4.620	1.00	7.36	66.88
Other Oil (>401 deg. F)	19.95	5.825	1.00	10.15	73.15

Table C.7 Carbon Dioxide Emission Factors for Stationary Combustion (continued)

Fuel Type	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor	CO_2 Emission Factor
Petroleum Products (Liquid)	kg C/ MMBtu	MMBtu/ barrel		kg CO_2/gallon	kg CO_2/MMBtu
Pentanes Plus	18.24	4.620	1.00	7.36	66.88
Petrochemical Feedstocks	19.37	5.428	1.00	9.18	71.02
Petroleum Coke	27.85	6.024	1.00	14.65	102.12
Still Gas	17.51	6.000	1.00	9.17	64.20
Special Naphtha	19.86	5.248	1.00	9.10	72.82
Unfinished Oils	20.33	5.825	1.00	10.34	74.54
Waxes	19.81	5.537	1.00	9.58	72.64
Non-Fossil Fuels (Solid)	kg C/ MMBtu	MMBtu/ short ton		kg CO_2/ metric ton	kg CO_2/MMBtu
Wood and Wood Waste (12% moisture content)*	25.60	15.38	1.00	1,591.35	93.87
Non-Fossil Fuels (Gas)	kg C/ MMBtu	Btu/ standard cubic foot		kg CO_2/ standard cubic foot	kg CO_2/MMBtu
Biogas*	14.20	502.50	1.00	varies	52.07

*The CO_2 emissions from burning wood, wood waste and biogas are considered biogenic and should not be included as a direct stationary emission in your inventory. You may report these emissions optionally. For biogas, please note that the values above are for the methane fraction of the biogas only. To report all of the biogenic CO_2 emissions associated with biogas, you would also need to report the CO_2 fraction of the biogas.

Note: CO_2 emission factors are calculated using the molar mass ratio of carbon dioxide to carbon (CO_2/C) of 44/12. Heat content factors are based on higher heating values (HHV). A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006).

Source: 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), Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, Annual Energy Review 2006 (2007), Tables A-1 and A-5) 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). Acetylene factor derived from API Compendium (February 2004), Exhibit 4.1(a) and HHV from GPSA.

Table C.8 Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Fuel Type and Sector

Fuel Type/End-Use Sector	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Coal		
Residential	0.316	0.0016
Commercial/Institutional	0.011	0.0016
Manufacturing/Construction	0.011	0.0016
Electric Power	0.001	0.0016
Petroleum Products		
Residential	0.011	0.0006
Commercial/Institutional	0.011	0.0006
Manufacturing/Construction	0.003	0.0006
Electric Power	0.003	0.0006
Natural Gas		
Residential	0.005	0.0001
Commercial/Institutional	0.005	0.0001
Manufacturing/Construction	0.001	0.0001
Electric Power	0.001	0.0001
Wood		
Residential	0.316	0.0042
Commercial/Institutional	0.316	0.0042
Manufacturing/Construction	0.032	0.0042
Electric Power	0.032	0.0042
Pulping Liquors		
Manufacturing	0.0025	0.0020

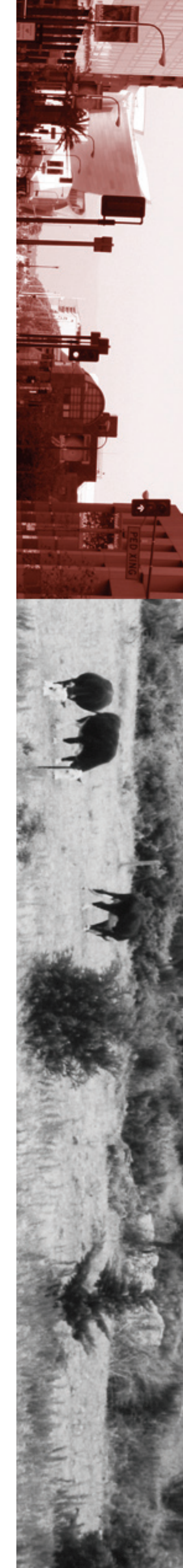
Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.1.

Table C.9 Methane and Nitrous Oxide Emission Factors for Stationary Combustion for Petroleum Products by Fuel Type and Sector

Fuel Type/End-Use Sector	CH_4 (kg/gallon)	N_2O (kg/gallon)
Residential		
Distillate Fuel	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel	0.0016	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Commercial/Institutional		
Distillate Fuel	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel	0.0016	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Manufacturing/Construction		
Distillate Fuel	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel	0.0004	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001
Electric Power		
Distillate Fuel	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel	0.0004	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001

Note: All emission factors were converted to kg/gallon using the petroleum products emission factors from Table C.8 and the heat content in MMBtu/barrel from Table C.7 specific to each petroleum fuel: heat content of fuel type (MMBtu/barrel) / 42 (barrels/gallon) x petroleum emission factor (kg/MMBtu) = petroleum emission factor (kg/gallon).

Source: Derived from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.1.



Appendix D Electricity Emission Factors for Non-U.S. Countries

Table D.1 Country-Specific Carbon Dioxide Electricity Emission Factors (lbs CO_2/MWh)*

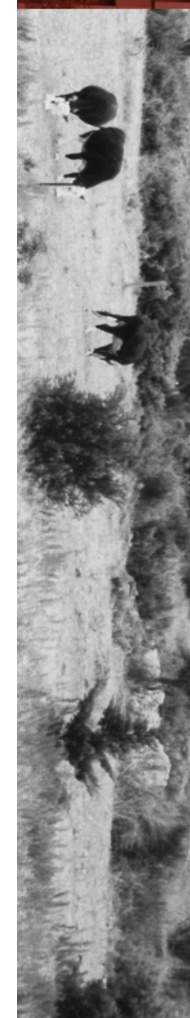
Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Albania	…	…	113	177	188	82	52	45	39	85	108	133	128	67	71	76
Algeria	…	…	1,458	1,438	1,502	1,541	1,479	1,503	1,556	1,528	1,512	1,515	1,542	1,543	1,543	1,479
Angola	…	…	398	288	400	391	418	537	446	753	843	841	781	822	743	756
Argentina	…	…	829	745	725	601	810	719	756	803	746	589	569	605	698	676
Armenia	…	…	881	241	279	472	508	581	569	495	520	536	338	326	264	305
Australia	1,788	1,795	1,810	1,777	1,724	1,710	1,815	1,908	1,940	1,923	1,906	1,863	1,967	1,922	1,860	1,925
Austria	539	555	460	427	456	472	506	502	458	430	404	428	429	520	507	496
Azerbaijan	…	…	…	1,889	1,062	1,111	1,151	1,175	1,196	1,359	1,435	1,240	1,082	1,156	1,129	1,113
Bahrain	…	…	2,325	1,962	1,932	1,797	1,789	1,688	1,811	1,877	1,913	1,852	1,841	1,947	1,943	1,962
Bangladesh	…	…	1,232	1,307	1,286	1,325	1,250	1,287	1,297	1,306	1,225	1,328	1,331	1,266	1,383	1,228
Belarus	…	…	…	734	753	714	677	683	670	655	676	655	661	653	669	659
Belgium	768	755	731	763	806	790	749	686	695	614	628	600	587	603	592	591
Benin	…	…	2,496	2,669	1,457	2,096	1,616	1,755	1,496	1,453	1,327	2,106	2,095	1,658	1,632	1,565
Bolivia	…	…	832	784	972	1,064	854	938	994	685	657	1,121	1,036	1,005	1,184	1,061
Bosnia-Herzegovina	…	…	2,040	3,257	386	422	570	1,335	1,731	1,535	1,547	1,576	1,369	1,420	1,325	1,364
Botswana	…	…	3,462	3,441	3,595	3,960	4,080	4,320	2,746	3,466	4,128	2,900	2,910	2,904	3,826	4,073
Brazil	…	…	134	122	113	122	126	137	137	182	194	229	189	175	188	186
Brunei Darussalam	…	…	2,016	2,056	2,165	1,941	1,884	1,886	1,908	1,832	1,753	1,761	1,804	1,789	1,788	1,739
Bulgaria	…	…	1,049	1,064	1,007	947	922	1,047	1,060	982	950	1,022	954	1,037	1,037	988
Cambodia	…	…	…	…	…	4,004	3,698	5,516	4,576	3,891	3,966	4,278	4,345	4,147	2,869	2,659
Cameroon	…	…	26	20	23	23	22	22	33	25	22	36	59	68	61	86
Canada	430	413	432	386	379	389	376	418	476	456	478	498	470	496	455	438
Chile	…	…	404	407	554	575	767	848	921	1,011	731	574	578	616	752	788
China	…	…	1,751	1,750	1,693	1,770	1,809	1,773	1,815	1,759	1,686	1,631	1,650	1,711	1,776	1,737
Colombia	…	…	590	502	408	451	383	457	470	390	442	421	413	389	360	360
Congo	…	…	16	19	22	20	15	15	20	252	0	0	0	0	0	0
Democratic Republic of Congo	…	…	7	6	9	8	8	10	10	9	8	8	8	8	7	7
Costa Rica	…	…	309	217	379	344	193	74	150	46	18	31	34	43	38	59
Côte d'Ivoire	…	…	542	632	706	607	750	927	1,141	912	837	868	902	847	890	1,142
Croatia	…	…	717	723	551	601	559	658	713	668	660	683	780	831	656	686
Cuba	…	…	2,020	2,324	2,430	2,506	2,437	2,445	2,579	2,275	2,257	2,186	2,404	2,493	2,235	2,177

* CO_2 emissions from fossil fuels consumed for electricity, combined heat and power and main activity heat plants divided by the output of electricity and heat generated from fossil fuels, nuclear, hydro (excluding pumped storage), geothermal, solar, etc.

Source: International Energy Agency Data Services, 2007. "CO_2 emissions from Fuel Combustion (2007 Edition)".

Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cyprus	…	…	1,833	1,835	1,843	1,822	1,845	1,864	1,868	1,898	1,856	1,722	1,675	1,846	1,712	1,747
Czech Republic	1,321	1,301	1,293	1,284	1,291	1,289	1,282	1,238	1,255	1,233	1,251	1,235	1,204	1,106	1,110	1,137
Denmark	1,050	1,116	1,035	1,007	1,036	948	1,029	929	859	801	748	740	732	787	679	625
Dominican Republic	…	…	1,657	1,597	1,859	1,931	1,641	1,715	1,831	1,873	1,675	1,451	1,618	1,420	1,292	1,265
Ecuador	…	…	612	429	380	692	501	650	634	521	475	600	620	658	666	814
Egypt	…	…	1,168	1,109	1,028	977	954	975	1,031	1,002	908	840	963	953	1,043	1,039
El Salvador	…	…	555	649	838	888	566	825	813	602	634	667	683	654	606	581
Eritrea	…	…	3,369	3,078	3,311	3,227	2,932	2,204	1,516	1,544	1,573	1,652	1,452	1,529	1,592	1,535
Estonia	…	…	1,430	1,367	1,364	1,519	1,497	1,498	1,586	1,558	1,537	1,511	1,482	1,595	1,545	1,466
Ethiopia	…	…	141	127	97	92	87	56	55	21	25	21	17	12	14	15
Finland	508	518	457	512	592	551	639	590	468	467	465	528	558	646	561	427
France	242	275	219	152	154	170	172	159	215	190	182	156	168	177	172	200
Gabon	…	…	627	659	461	563	695	695	758	718	718	600	621	675	709	812
Georgia	…	…	809	704	603	1,076	366	336	357	340	426	293	114	118	172	197
Germany	1,260	1,287	1,219	1,212	1,208	1,174	1,157	1,141	1,121	1,090	1,093	1,116	1,143	966	960	770
Ghana	…	…	0	7	8	6	1	9	510	412	173	285	467	658	184	449
Gibraltar	…	…	1,714	1,713	1,665	1,697	1,666	1,712	1,697	1,697	1,683	1,670	1,684	1,671	1,697	1,638
Greece	2,185	2,074	2,113	2,058	1,949	1,923	1,826	1,916	1,896	1,811	1,794	1,835	1,797	1,706	1,713	1,712
Guatemala	…	…	650	619	651	674	567	527	991	745	864	928	1,067	890	956	846
Haiti	…	…	685	475	199	722	877	1,252	837	637	762	749	881	705	663	678
Honduras	…	…	88	139	303	721	519	586	839	574	618	726	621	776	993	905
Hong Kong, China	…	…	1,806	1,897	1,920	1,879	1,829	1,596	1,632	1,576	1,567	1,585	1,596	1,750	1,829	1,785
Hungary	1,035	1,015	1,070	1,011	974	983	955	951	942	914	908	870	863	928	859	747
Iceland	1	1	1	2	2	4	3	2	6	8	1	1	1	1	1	1
India	…	…	1,960	2,009	1,931	2,041	2,140	2,078	2,031	2,026	2,069	2,059	2,026	1,991	2,077	2,080
Indonesia	…	…	1,409	1,667	1,414	1,283	1,407	1,489	1,434	1,491	1,417	1,630	1,573	1,709	1,654	1,699
Islamic Republic of Iran	…	…	1,236	1,289	1,301	1,334	1,317	1,306	1,240	1,284	1,253	1,273	1,234	1,176	1,174	1,177
Iraq	…	…	1,305	1,372	1,594	1,540	1,540	1,528	1,495	1,494	1,612	1,792	1,656	1,735	1,549	1,545
Ireland	1,653	1,661	1,674	1,624	1,608	1,607	1,605	1,586	1,577	1,538	1,409	1,488	1,405	1,317	1,260	1,288
Israel	…	…	1,809	1,813	1,810	1,811	1,824	1,812	1,688	1,692	1,678	1,704	1,814	1,802	1,780	1,692
Italy	1,265	1,210	1,181	1,158	1,139	1,205	1,158	1,136	1,138	1,098	1,111	1,070	1,122	1,157	905	894
Jamaica	…	…	1,969	2,734	1,844	1,958	1,825	1,825	1,832	1,814	1,810	1,815	1,770	1,751	1,731	1,573
Japan	949	928	941	901	939	900	894	862	836	871	879	881	925	973	937	945
Jordan	…	…	1,974	1,896	1,833	1,838	1,787	1,764	1,779	1,648	1,562	1,548	1,633	1,500	1,505	1,455
Kazakhstan	…	…	2,746	2,691	3,255	2,414	2,476	2,298	2,495	2,461	2,680	2,232	2,597	2,628	2,599	2,506
Kenya	…	…	149	159	180	160	198	229	622	907	1,239	864	597	441	617	676
Dem. People's Republic of Korea	…	…	1,194	1,111	1,117	1,059	1,146	1,228	1,100	1,216	1,285	1,282	1,250	1,193	1,163	1,149

Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Korea	1,129	1,213	1,274	1,233	1,197	1,172	1,164	1,212	1,090	1,056	1,105	1,106	937	982	979	922
Kuwait	…	…	1,421	1,339	1,367	1,407	1,406	1,428	1,432	1,484	1,519	1,478	1,376	1,462	1,661	1,780
Kyrgyzstan	…	…	345	254	180	279	286	303	271	229	234	224	233	207	198	180
Latvia	…	…	609	593	552	525	579	481	435	478	441	418	415	403	367	357
Lebanon	…	…	1,440	1,551	1,472	1,442	1,557	1,521	1,727	1,796	1,616	1,656	1,591	1,562	1,244	1,471
Libya	…	…	1,623	1,600	1,935	2,494	2,361	2,339	2,358	2,328	2,254	2,231	2,140	2,157	1,959	1,983
Lithuania	…	…	410	410	474	381	382	365	380	389	348	317	264	248	243	286
Luxembourg	5,706	5,446	5,476	5,433	4,646	2,954	2,630	1,786	549	568	562	529	725	728	736	723
FYR of Macedonia	…	…	1,828	1,794	1,792	1,850	1,762	1,607	1,656	1,511	1,501	1,715	1,593	1,466	1,497	1,422
Malaysia	…	…	1,374	1,332	1,226	1,227	1,233	1,028	1,189	1,163	1,139	1,192	1,303	1,158	1,171	1,228
Malta	…	…	2,256	3,068	2,566	2,120	2,158	2,076	2,065	2,003	1,913	2,267	1,807	1,794	1,988	1,966
Mexico	1,181	1,179	1,123	1,124	1,237	1,117	1,116	1,151	1,260	1,237	1,248	1,253	1,230	1,234	1,152	1,136
Republic of Moldova	…	…	1,561	1,355	1,275	1,134	1,565	1,610	1,520	1,398	1,639	1,704	1,642	1,666	1,131	1,137
Mongolia	…	…	1,413	1,567	1,363	1,344	1,256	1,165	1,313	1,234	1,293	1,290	1,352	1,220	1,160	1,176
Morocco	…	…	1,821	1,968	1,860	1,915	1,555	1,520	1,608	1,672	1,697	1,684	1,686	1,623	1,651	1,714
Mozambique	…	…	471	330	144	141	121	64	6	6	10	9	7	7	7	3
Myanmar	…	…	971	1,005	1,066	1,120	1,271	1,156	1,324	1,262	1,008	894	829	938	914	804
Namibia	…	…	60	395	573	82	106	125	99	66	46	65	61	59	60	58
Nepal	…	…	110	129	156	56	55	160	162	76	27	16	4	3	3	3
Netherlands	1,328	1,287	1,259	1,267	1,186	1,167	1,104	1,101	1,035	1,031	985	1,019	1,011	1,030	970	852
Netherlands Antilles	…	…	1,583	1,583	1,587	1,581	1,584	1,578	1,582	1,585	1,580	1,581	1,582	1,580	1,582	1,583
New Zealand	282	287	384	306	255	246	307	470	472	524	508	608	544	639	531	607
Nicaragua	…	…	974	874	988	1,067	1,097	1,184	1,394	1,334	1,344	1,351	1,240	1,229	1,229	1,188
Nigeria	…	…	801	865	699	644	669	700	745	771	896	750	781	750	881	888
Norway	8	10	9	9	11	10	14	12	12	13	9	13	12	18	15	12
Oman	…	…	1,884	1,871	1,875	1,831	1,732	1,670	1,655	1,784	1,754	1,801	1,829	1,882	1,952	1,884
Pakistan	…	…	867	847	862	893	976	1,000	907	1,031	1,057	1,020	976	816	875	837
Panama	…	…	813	654	663	699	499	617	984	494	509	881	596	785	586	610
Paraguay	…	…	1	1	0	5	1	1	1	1	0	0	0	0	0	0
Peru	…	…	475	393	345	411	449	464	430	377	334	265	316	326	454	436
Philippines	…	…	1,066	1,056	1,144	1,121	1,133	1,256	1,304	1,104	1,098	1,168	1,063	1,014	1,007	1,092
Poland	1,447	1,434	1,439	1,412	1,418	1,489	1,465	1,470	1,465	1,466	1,481	1,456	1,460	1,460	1,466	1,453
Portugal	1,140	1,152	1,371	1,204	1,096	1,256	946	1,029	1,023	1,189	1,058	976	1,130	912	997	1,098
Qatar	…	…	2,235	2,293	2,381	2,493	2,316	2,237	1,907	1,815	1,700	1,722	1,723	1,718	1,431	1,362
Romania	…	…	903	848	1,006	971	980	849	775	793	872	909	909	995	922	869
Russia	…	…	680	642	653	644	754	724	720	721	707	709	720	726	716	745
Saudi Arabia	…	…	1,836	1,847	1,798	1,797	1,768	1,783	1,796	1,789	1,785	1,716	1,656	1,630	1,674	1,648



Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Senegal	…	…	2,009	2,079	2,054	1,941	1,889	1,935	1,936	2,002	1,724	1,762	1,423	1,147	1,224	1,398
Serbia and Montenegro	…	…	1,645	1,671	1,539	1,843	1,762	1,799	1,770	1,498	1,653	1,567	1,629	1,691	1,613	1,649
Singapore	…	…	1,854	2,214	2,153	2,069	1,940	1,696	1,707	1,446	1,463	1,399	1,312	1,265	1,226	1,199
Slovak Republic	834	857	794	909	795	815	800	835	774	769	588	548	494	563	545	512
Slovenia	…	…	807	823	737	743	700	853	868	809	730	752	820	810	742	724
South Africa	…	…	1,886	1,941	1,904	1,936	1,897	1,917	2,045	1,961	1,969	1,827	1,807	1,863	1,908	1,870
Spain	943	934	1,062	924	918	1,007	791	864	839	981	947	845	964	840	843	869
Sri Lanka	…	…	420	163	141	112	511	579	450	504	942	896	958	833	945	877
Sudan	…	…	662	1,139	779	1,026	1,065	1,127	1,027	944	1,175	1,176	1,393	1,639	1,826	1,870
Sweden	106	128	112	115	123	110	162	111	120	106	93	95	115	131	113	98
Switzerland	48	54	61	46	44	48	56	50	61	48	49	47	48	50	52	58
Syria	…	…	1,205	1,236	1,282	1,291	1,299	1,303	1,314	1,319	1,249	1,231	1,221	1,240	1,227	1,295
Taiwan	…	…	1,080	1,115	1,110	1,134	1,149	1,214	1,234	1,278	1,331	1,358	1,335	1,395	1,384	1,393
Tajikistan	…	…	193	144	87	110	135	101	99	91	91	91	60	60	62	60
United Republic of Tanzania	…	…	301	353	490	627	423	859	93	278	425	154	125	112	133	1,337
Thailand	…	…	1,425	1,389	1,374	1,336	1,379	1,397	1,341	1,314	1,244	1,240	1,187	1,164	1,186	1,171
Togo	…	…	545	485	936	408	471	827	1,001	602	790	2,411	478	286	1,099	1,045
Trinidad and Tobago	…	…	1,608	1,668	1,572	1,567	1,518	1,495	1,564	1,560	1,524	1,529	1,702	1,612	1,674	1,563
Tunisia	…	…	1,511	1,492	1,420	1,296	1,328	1,341	1,341	1,318	1,266	1,288	1,243	1,222	1,173	1,062
Turkey	1,287	1,308	1,309	1,156	1,263	1,174	1,187	1,214	1,231	1,272	1,159	1,214	1,055	988	941	954
Turkmenistan	…	…	…	…	…	…	…	1,390	1,345	1,743	1,753	1,753	1,753	1,753	1,753	1,753
Ukraine	…	…	809	846	782	803	730	708	726	742	759	722	711	835	689	693
United Arab Emirates	…	…	1,639	1,639	1,639	1,626	1,632	1,652	1,566	1,560	1,606	1,646	1,695	1,771	2,013	1,860
United Kingdom	1,497	1,461	1,426	1,259	1,194	1,206	1,156	1,067	1,057	956	990	1,049	1,017	1,057	1,072	1,042
Uruguay	…	…	196	148	26	117	229	154	73	413	125	6	9	4	332	227
Uzbekistan	…	…	1,187	1,208	1,083	956	982	1,016	1,070	1,067	1,012	1,030	1,048	1,002	976	977
Venezuela	…	…	500	533	489	483	438	490	523	480	463	622	612	540	541	497
Vietnam	…	…	668	558	644	648	703	900	1,031	874	927	865	934	826	898	894
Yemen	…	…	1,953	1,700	2,020	2,084	2,122	2,051	2,194	2,030	2,049	2,050	2,026	1,949	1,939	1,864
Zambia	…	…	29	24	19	16	16	22	22	15	15	15	15	15	15	15
Zimbabwe	…	…	2,270	2,283	2,407	2,028	1,938	1,735	2,002	1,790	1,631	1,870	1,581	1,136	1,261	1,262

Appendix E Electricity Emission Factors for Historical Reporting Purposes

Tables E.1 and E.2 provide carbon dioxide electricity emission factors by eGRID subregion for use in reporting historical data for calendar year 2007 and for 1990 through 2006, respectively. Table E.3 provides methane and nitrous oxide emission factors by state for use in reporting historical data for calendar years 1990 through 2007. These emission factors should not be used for current year reporting. For current year reporting, use the emission factors in Appendix C.

Table E.1 Carbon Dioxide Electricity Emission Factors, Calendar Year 2007

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate (lbs/MWh)
AKGD	ASCC Alaska Grid	1,257.19
AKMS	ASCC Miscellaneous	480.10
AZNM	WECC Southwest	1,254.02
CAMX	WECC California	878.71
ERCT	ERCOT All	1,420.56
FRCC	FRCC All	1,327.66
HIMS	HICC Miscellaneous	1,456.17
HIOA	HICC Oahu	1,728.12
MROE	MRO East	1,858.72
MROW	MRO West	1,813.81
NEWE	NPCC New England	908.90
NWPP	WECC Northwest	921.10
NYCW	NPCC NYC/Westchester	922.22
NYLI	NPCC Long Island	1,412.20
NYUP	NPCC Upstate NY	819.68
RFCE	RFC East	1,095.53
RFCM	RFC Michigan	1,641.41
RFCW	RFC West	1,556.39
RMPA	WECC Rockies	2,035.81
SPNO	SPP North	1,971.42
SPSO	SPP South	1,761.14
SRMV	SERC Mississippi Valley	1,135.46
SRMW	SERC Midwest	1,844.34
SRSO	SERC South	1,490.37
SRTV	SERC Tennessee Valley	1,494.89
SRVC	SERC Virginia/Carolina	1,146.39

Source: EPA eGRID2006 Version 2.1, April 2007 (Year 2004 Data).

Figure E.1 shows the eGRID historical subregions. Use this map to identify your subregion for reporting historical data for calendar year 2007. Note that the subregions are the same for calendar year 2007 as the current year.

Figure E.1 Historical eGRID Subregions, Calendar Year 2007

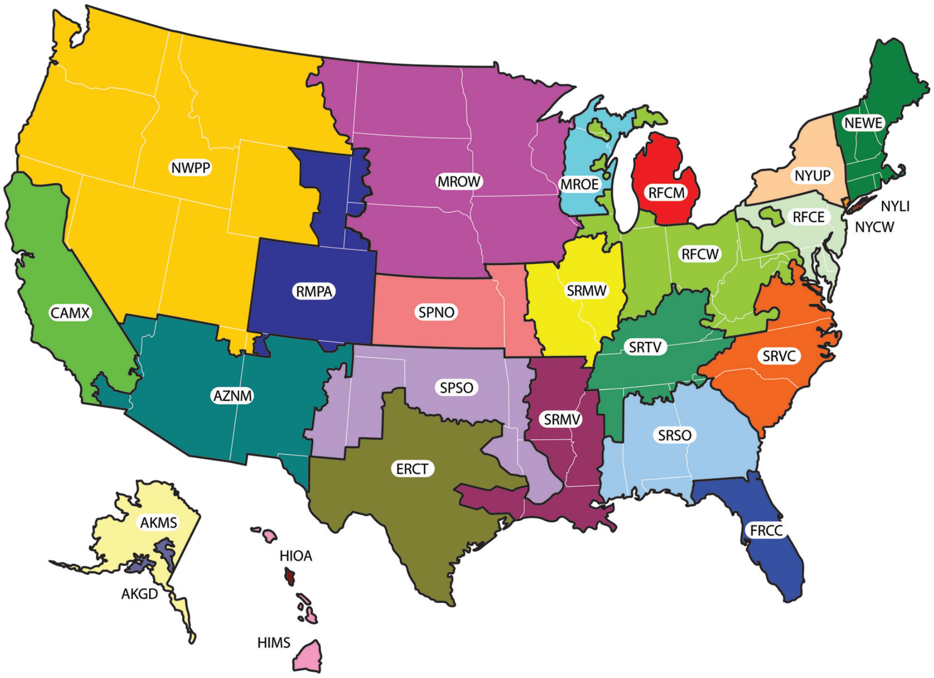


Table E.2 Carbon Dioxide Electricity Emission Factors, Calendar Years 1990 - 2006

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate (lbs/MWh)
AKGD	ASCC Alaska Grid	1,399.95
AKMS	ASCC Miscellaneous	757.81
CALI	WECC California	804.54
ECMI	ECAR Michigan	1,632.06
ECOV	ECAR Ohio Valley	1,966.53
ERCT	ERCOT All	1,408.27
FRCC	FRCC All	1,390.04
HIMS	HICC Miscellaneous	1,702.93
HIOA	HICC Oahu	1,721.69
MAAC	MAAC All	1,097.56
MANN	MAIN North	1,761.09
MANS	MAIN South	1,237.29
MAPP	MAPP All	1,838.83
NEWE	NPCC New England	897.11
NWGB	WECC Great Basin	852.31
NWPN	WECC Pacific Northwest	671.04
NYCW	NPCC NYC/Westchester	1,090.13
NYLI	NPCC Long Island	1,659.76
NYUP	NPCC Upstate NY	843.04
OFFG	Off-Grid	1,706.71
ROCK	WECC Rockies	1,872.51
SPNO	SPP North	2,011.15
SPSO	SPP South	1,936.65
SRMV	SERC Mississippi Valley	1,331.34
SRSO	SERC South	1,561.51
SRTV	SERC Tennessee Valley	1,372.70
SRVC	SERC Virginia/Carolina	1,164.19
WSSW	WECC Southwest	1,423.95

Source: EPA eGRID2002 Version 2.01 Location (Operator)-Based eGRID Subregion File (Year 2000 Data).

Figure E.2 shows the eGRID historical subregions. Use this map to identify your subregion for reporting historical data for calendar years 1990 - 2006.

Figure E.2 Historical eGRID Subregions, Calendar Years 1990 - 2006

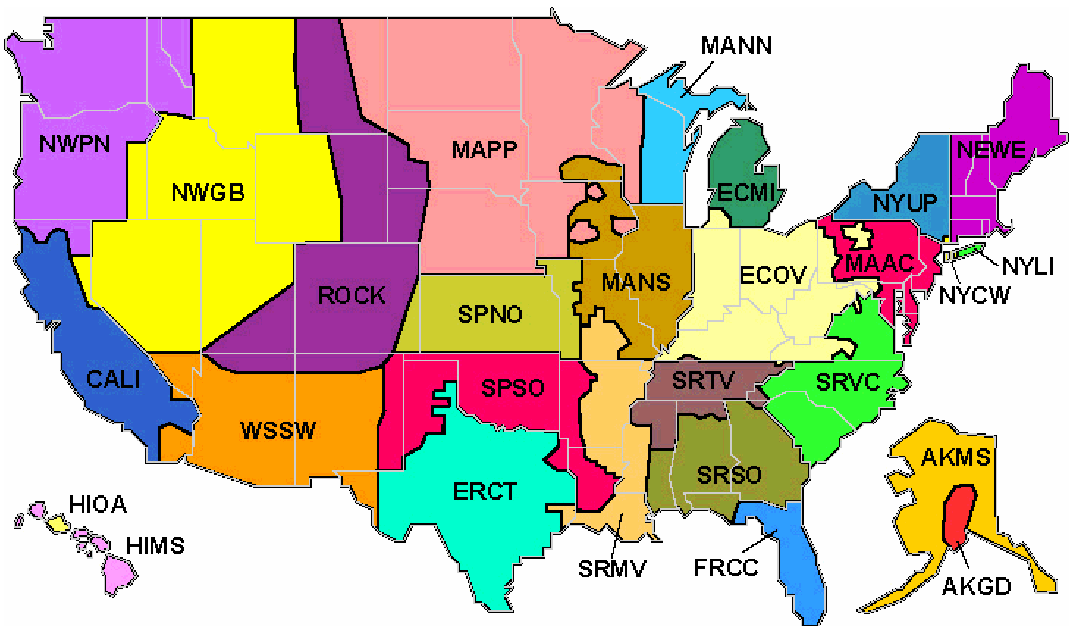


Table E.3 Methane and Nitrous Oxide Electricity Emission Factors by State, Calendar Years 1990 - 2007

Region/State	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
Alabama	0.0137	0.0223
Alaska	0.0068	0.0089
Arizona	0.0068	0.0154
Arkansas	0.0125	0.0203
California	0.0067	0.0037
Colorado	0.0127	0.0289
Connecticut	0.0174	0.0120
Delaware	0.0123	0.0227
Florida	0.0150	0.0180
Georgia	0.0129	0.0226
Hawaii	0.0214	0.0183
Idaho	0.0080	0.0033
Illinois	0.0082	0.0180
Indiana	0.0143	0.0323
Iowa	0.0138	0.0298
Kansas	0.0112	0.0254
Kentucky	0.0140	0.0321
Louisiana	0.0094	0.0112
Maine	0.0565	0.0270
Maryland *	0.0118	0.0206
Massachusetts	0.0174	0.0159
Michigan	0.0146	0.0250
Minnesota	0.0157	0.0247
Mississippi	0.0132	0.0165
Missouri	0.0126	0.0288
Montana	0.0108	0.0227
Nebraska	0.0095	0.0219
Nevada	0.0090	0.0195
New Hampshire	0.0172	0.0141
New Jersey	0.0077	0.0079
New Mexico	0.0131	0.0296
New York	0.0081	0.0089
North Carolina	0.0105	0.0203
North Dakota	0.0147	0.0339

Table E.3 Methane and Nitrous Oxide Electricity Emission Factors by State, Calendar Years 1990 - 2007 (continued)

Region/State	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
Ohio	0.0130	0.0288
Oklahoma	0.0110	0.0223
Oregon	0.0033	0.0034
Pennsylvania	0.0107	0.0203
Rhode Island	0.0068	0.0047
South Carolina	0.0091	0.0145
South Dakota	0.0053	0.0121
Tennessee	0.0105	0.0212
Texas	0.0077	0.0146
Utah	0.0134	0.0308
Vermont	0.0096	0.0039
Virginia	0.0137	0.0192
Washington	0.0037	0.0040
West Virginia	0.0137	0.0316
Wisconsin	0.0138	0.0260
Wyoming	0.0147	0.0338

* Includes the District of Columbia.

Note: All emission factors for electricity generation were derived based on higher heating values (HHV).

Source: Emission factors are derived from: U.S. Department of Energy, Revised/Updated State-level Greenhouse Gas Emission Factors for Electricity (April 2002), http://www.eia.doe.gov/oiaf/1605/e-factor.html. Note: These state-level electricity generation emission factors represent average emissions per kWh or MWh generated by electric utilities for the 1998-2000 time period. They do not include emissions from power produced by non-utility generators.

Appendix F Industry-Specific Metrics for Determining Emission Intensity

The following table provides industry-specific metrics that may be used to measure energy and GHG emissions. It was compiled by researchers at the Lawrence Berkeley National Laboratory (LBNL).

Table F.1 Industry-Specific Metrics, Ranked by California Industrial Combined Electricity and Natural Gas Consumption (Listed by Largest to Smallest Subsector)

SIC Code	Description	Energy Metric	Emissions Metric	Source
13	**Oil and Gas Extraction**			
131	Crude petroleum and natural gas	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
132	Natural gas liquids	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
138	Oil and gas field services	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
29	**Petroleum and Coal Products**			
		Energy Intensity Index (EII)		Solomon Associates, 2001
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
291	Petroleum refining	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/cubic meter fossil fuels	GHG/cubic meter fossil fuels	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
295	Asphalt paving and roofing materials	N/A		
299	Misc. petroleum and coal products	N/A		

SIC Code	Description	Energy Metric	Emissions Metric	Source
20	**Food and Kindred Products**			
201	Meat products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne	GHG/tonne	Institute for Energy Technology, 1998
202	Dairy products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/liter weighted production	GHG/liter weighted production	Institute for Energy Technology, 1998
		Energy/tonne milk and cream	GHG/kiloliter milk and cream	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
203	Preserved fruits and vegetables	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
204	Grain mill products	N/A		
205	Bakery products	Energy/kg bread	GHG/kg bread	Institute for Energy Technology, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
206	Sugar and confectionery products	Energy efficiency index		Ministry of Economic Affairs, 1998
207	Fats and oils	Energy efficiency index		Ministry of Economic Affairs, 1998

SIC Code	Description	Energy Metric	Emissions Metric	Source
20	**Food and Kindred Products**			
208	Beverages	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Soft drinks	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Brewery products	Energy/hectoliter of beer equiv	GHG/hectoliter of beer equiv	Institute for Energy Technology, 1998
		Energy/hectoliter of beer	GHG/hectoliter of beer	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
209	Misc. food and kindred products	N/A		
32	**Stone, Clay, and Glass Products**			
	Glass and glass products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
321	Flat glass	N/A		
322	Glass & glassware, pressed or blown	N/A		
323	Products of purchased glass	N/A		
324	Cement, hydraulic	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne clinker	GHG/tonne clinker	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	
325	Structural clay products (bricks, tile)	Energy efficiency index		Ministry of Economic Affairs, 1998

SIC Code	Description	Energy Metric	Emissions Metric	Source
32	**Stone, Clay, and Glass Products**			
326	Pottery	Energy Efficiency Index		Ministry of Economic Affairs, 1998
327	Concrete, gypsum & plaster products	N/A		
328	Cut stone and stone products	N/A		
329	Misc nonmetallic mineral products	N/A		
28	**Chemicals and Allied Products**			
		Energy/$ gross output	GHG/GDP	Ministry of Economic Affairs, 1998
		Energy/GDP		Nyboer and Laurin, 2001a
		Energy/GDP		Nyboer and Laurin, 2001b
281	Industrial inorganic chemicals	Energy/tonne inorganic chemicals	GHG/tonne inorganic chemicals	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
286	Industrial organic chemicals	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
287	Agricultural chemicals	Energy/tonne chemical fertilizers	GHG/tonne chemical fertilizers	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
	Chemical fertilizers	Energy/tonne fertilizers	GHG/tonne fertilizers	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
36	**Electronic and Other Electric Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
33	**Primary Metal Industries**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
331	Blast furnace and basic steel	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne steel	GHG/tonne steel	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
332	Iron and steel foundries	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Non-ferrous Metal Smelters & Refineries	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Primary Production of Aluminum	Energy/tonne aluminum	GHG/tonne aluminum	Institute for Energy Technology, 1998
3335	Aluminum rolling and drawing	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Copper/Alloy Roll, Cast & Extrude	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
26	**Paper and Allied Products**			
		Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
26	**Paper and Allied Products**			
261	Pulp mills	Energy/tonne pulpwood	GHG/tonne pulpwood	Institute for Energy Technology, 1998
		Energy/tonne thermomechanical pulp	GHG/tonne thermomechanical pulp	Nyboer and Laurin, 2001a
		Energy/tonne chemical pulp	GHG/tonne chemical pulp	Nyboer and Laurin, 2001b
		Energy/tonne market pulp	GHG/tonne market pulp	
		Energy/$ gross output	GHG/$ gross output	
		Energy/GDP	GHG/GDP	
262	Paper mills	Energy/tonne paper	GHG/tonne paper	Institute for Energy Technology, 1998
		Energy/tonne pulp and paper	GHG/tonne pulp and paper	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
263	Paperboard mills	Energy/tonne paperboard	GHG/tonne paperboard	Nyboer and Laurin, 2001a
34	**Fabricated Metal Products**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
37	**Transportation Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
371	Motor vehicles and equipment	Energy/1000 cars and trucks	GHG/1000 cars and trucks	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
3714	Motor vehicle parts and accessories	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
35	**Industrial Machinery and Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
30	**Rubber and Miscellaneous Plastics Products**			
		Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne of rubber products	GHG/tonne rubber products	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
22	**Textile Mill Products**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
		Energy efficiency index		Ministry of Economic Affairs, 1998
227	Carpets and rugs	N/A		
24	Lumber and wood products	N/A		
14	Nonmetallic mineral, except fuels	N/A		
38	Instruments and related products	N/A		
27	Printing and publishing	N/A		
15	General building contractors	N/A		
2	Agriculture production - livestock	N/A		
39	Miscellaneous manufacturing industries	N/A		
23	Apparel and other textile products	N/A		
25	Furniture and fixtures	N/A		
10	Metal mining	N/A		
31	Leather and leather products	N/A		

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