

**Greenhouse Gas Emission Inventory
and Management Strategy Guidelines
for Water Utilities**

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FOREWORD

The Water Research Foundation is a nonprofit corporation that is dedicated to the implementation of a research effort to help utilities respond to regulatory requirements and traditional high-priority concerns of the industry. The research agenda is developed through a process of consultation with subscribers and drinking water professionals. Under the umbrella of a Strategic Research Plan, the Research Advisory Council prioritizes the suggested projects based upon current and future needs, applicability, and past work; the recommendations are forwarded to the Board of Trustees for final selection. The foundation also sponsors research projects through the unsolicited proposal process; the Collaborative Research, Research Applications, and Tailored Collaboration programs; and various joint research efforts with organizations such as the U.S. Environmental Protection Agency, the U.S. Bureau of Reclamation, and the Association of California Water Agencies.

This publication is a result of one of these sponsored studies, and it is hoped that its findings will be applied in communities throughout the world. The following report serves not only as a means of communicating the results of the water industry's centralized research program but also as a tool to enlist the further support of the nonmember utilities and individuals.

Projects are managed closely from their inception to the final report by the foundation's staff and large cadre of volunteers who willingly contribute their time and expertise. The foundation serves a planning and management function and awards contracts to other institutions such as water utilities, universities, and engineering firms. The funding for this research effort comes primarily from the Subscription Program, through which water utilities subscribe to the research program and make an annual payment proportionate to the volume of water they deliver and consultants and manufacturers subscribe based on their annual billings. The program offers a cost-effective and fair method for funding research in the public interest.

A broad spectrum of water supply issues is addressed by the foundation's research agenda: resources, treatment and operations, distribution and storage, water quality and analysis, toxicology, economics, and management. The ultimate purpose of the coordinated effort is to assist water suppliers to provide the highest possible quality of water economically and reliably. The true benefits are realized when the results are implemented at the utility level. The foundation's trustees are pleased to offer this publication as a contribution toward that end.

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EXECUTIVE SUMMARY

This manual provides guidance for development of greenhouse gas (GHG) emission inventories for water utilities, and was prepared as part of the Water Research Foundation (Foundation) Project 4156. Detailed goals of the project and organization of this document are discussed in Chapter 1.

There are many reasons that water utilities may begin to assess the emissions directly or indirectly caused by their operations and to evaluate the projects or actions that may reduce or offset those emissions. These include, but are not limited to, existing and developing regulations requiring inventory and reporting of emissions, developing “carbon tax” and “cap-and-trade” regulation of GHG emissions, stakeholder initiatives demanding action, and environmental stewardship goals.

In most circumstances, GHG emissions cannot be directly measured. The primary exception to this generalization is electric utilities and other facilities that operate continuous emission monitors (CEMs) to track regulated air pollutant emissions and that also directly or indirectly measure carbon dioxide (CO₂) emissions. Otherwise, GHG emissions must be calculated using measured “activity” data for parameters such as quantities of fuel combusted, electricity consumed, or vehicle miles driven. These parameters are then typically multiplied by “emission factors” that estimate the quantity of GHG emitted per unit of activity. Various protocols exist describing the preferred data sources, procedures for determination of emission factors, calculation procedures, and other issues required to produce accurate, complete, and transparent GHG emission inventories.

The water industry contributes to GHG emissions primarily through combustion of fuels in stationary sources or mobile sources (e.g., vehicles) and through consumption of electricity. These primary sources are affected by characteristics specific to each water utility, including source water location, raw water quality and the treatment required, size of the overall organization, and distribution system topography. These factors, as well as others, contribute to a water utility’s baseline GHG emissions inventory.

By understanding the source of its GHG emissions and generating a baseline emissions inventory for the organization as a whole, a water utility may be able to identify projects to reduce emissions. This document describes the steps required to develop a management system for the development and maintenance of such an emission inventory, issues relevant to the comparison of the emissions of one water utility to another, and for beginning the process of assessing and prioritizing emission reduction opportunities.

According to most published protocols, GHG emissions are divided into three categories. Scope 1 (Direct) GHG emissions are released from sources within the organizational boundaries of the entity being inventoried. Scope 2 (Indirect) GHG emissions are released from sources outside of the organizational boundaries of the entity being inventoried, but are a consequence of the energy purchases of the entity (for example, emissions from the power plant that generates the electricity consumed by the entity). Thus, by definition, Scope 2 emissions are double-counted, once as Scope 1 emissions by the energy producer, and again as Scope 2 emissions by the energy consumer. Scope 3 (Optional Indirect) GHG emissions are a broad category that covers all other releases that are an indirect consequence of the entity’s operations, or which could be within the sphere of influence of the entity.

A water utility’s obligations for reporting of GHG emissions is limited to Scope 1 and Scope 2 emissions under most voluntary reporting programs, existing mandatory reporting

programs, and probable scenarios of future mandatory reporting programs or cap-and-trade emission control schemes. However, the ability of water utilities to effect significant emission reductions or sequestration of GHGs may require inclusion of projects impacting Scope 3 emissions or other projects outside of their own boundaries. This document provides detailed explanation of emission estimation techniques for Scope 1 and Scope 2 emissions common to water utilities; because of the breadth of project types involved, it does not provide a detailed methodology for estimation of Scope 3 emissions. For clarity, this document refers to the sum of Scope 1 and Scope 2 emissions as an entity's "inventory," and the sum of the Scope 1 and 2 inventory plus the broader Scope 3 impacts caused by its operations as the entity's "footprint."

The World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol was one of the first widely accepted protocols for development of entity-wide GHG inventories, and is the basis for most subsequent protocols. Other protocols that may be of relevance to water utilities in the United States include guidelines developed by the California Climate Action Registry (CCAR), The Climate Registry (TCR), U.S. Environmental Protection Agency (USEPA) Climate Leaders, and International Organization for Standardization (ISO) 14064. Existing protocols for development of entity-wide emission inventories are discussed in Chapter 2 of this document.

Subsequent to the initial development of this document, CCAR has changed its mission to focus on registry of GHG offset (reduction) projects. Initially established as a registry of entity-wide emission inventories for organizations with operations in California, CCAR staff were instrumental in the establishment of TCR, which has a similar mission but with a multi-state focus. CCAR's role became somewhat redundant with that of TCR, and as such, recently announced new primary goals of 1) recognizing early action by its members under future regulatory scenarios, 2) focusing on GHG reduction projects, and 3) remaining active in GHG policy issues. CCAR has recently announced the development of The Climate Action Reserve, which will track development and transaction of voluntary GHG reductions. Draft versions of this guidance used example emission estimation methodologies from CCAR documentation in Chapters 7 through 9; because those CCAR methodologies are still relevant and consistent with methodology of TCR and other protocols, those references have been retained in this report.

Six categories of GHGs are typically included in inventories: carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbon (HFC), perfluorocarbon (PFC), and sulfur hexafluoride (SF₆). Further information on these compounds, their relative heat-trapping ability expressed as "global warming potential," the types of sources of these emissions, emission reporting concepts, and procedures for the definition of inventory boundaries are described in Chapters 3 and 4.

Carbon offsets are tradable commodities that represent the ability to claim the GHG reduction impacts of projects. Typically these are quantified according to existing compliance or voluntary protocols and are certified by third parties, after which the reductions can be claimed against an entity's Scope 1 or Scope 2 emission inventories. Additional detail on the concept of offsets is covered in Chapter 3.

It is recommended that all entities preparing a GHG inventory develop a management system to ensure that the resulting product meets the fundamental accounting principles of relevance, completeness, consistency, transparency, and accuracy. These terms are defined in Chapter 3, and development of appropriate management systems is described in Chapter 5.

It is suggested that water utilities organize inventory data according to their operational functions of source, treatment, distribution, buildings/infrastructure, fleet, and other operations.

This strategy is explained in Chapter 6. In addition, issues regarding onsite generation of renewable power (for example, hydropower) and the impact of water conservation projects, which are somewhat unique to the water industry, are discussed in this chapter.

Estimation of Scope 2 emissions from use of purchased electricity is typically performed by quantifying total power consumption by location, multiplying the result by supplier-specific or electric grid subregion-specific emission factors (which represent the average emissions intensity of the plants supplying the power), and summing the subtotals. Additional detail and methods for determining emission factors are provided in Chapter 7.

Scope 1 emissions from mobile sources (for example, trucks and other fleet vehicles that are within the entity's organizational boundaries) include CO₂, CH₄, and N₂O. CO₂ emissions can be directly calculated from the total quantity of fuel and information on the carbon content of the fuel. Standard factors for the carbon content can be applied. Emissions of CH₄ and N₂O, while typically small compared to CO₂ emissions, are more dependent on the emission-control technology for the vehicles; calculating these emissions requires data on the vehicle type and miles driven. Standard factors are available for estimation of CH₄ and N₂O emissions based on fuel and emission control type. Chapter 8 details calculation methodology for mobile sources.

Scope 1 emissions from stationary combustion (for example, natural gas use for comfort heating) are similarly calculated. CO₂ emissions are again the predominant impact, and they can be estimated from total quantity of fuel burned and data on the carbon content of the fuel. Standard factors can again be used for carbon content. CH₄ and N₂O emissions also have to be quantified and are again dependent on combustor parameters and fuel type. Standard factors are available for estimation of CH₄ and N₂O emissions. Chapter 9 provides additional information on calculating stationary combustion emissions.

Emission source types that are unique or of special relevance to water utilities include byproducts of ozone generation, onsite granular activated carbon (GAC) regeneration, impacts of land use, eutrophication in water storage reservoirs, sludge management, and biological denitrification. The authors reviewed available information on these source categories and found that all will contribute very small fractions of a typical water utility's total impact and, thus, would typically be considered "*de minimis*" sources. Methods for estimation of these small sources is detailed in Chapter 10.

Suggested procedures for development of an overall climate change strategy for a water utility will begin with an estimation of GHG inventory and footprint, as well as the potential impacts of climate change on the utility (for example, a change in source water supply). After the development of an inventory and footprint, potential internal and external projects for mitigation of impacts can be identified and assessed. Potential internal project types may include energy efficiency efforts, addition of onsite renewable generation, and fleet management. The breadth of potential external project types is much greater and may include water conservation projects, terrestrial or geologic sequestration, energy efficiency, CH₄ emission reductions, and many other project types that could be pursued through direct funding or via carbon brokers. After potential project types are identified, an overall reduction strategy can be developed, funding appropriated, and external messages developed. Additional detail on development of a management strategy is provided in Chapter 11.

The pace of regulatory developments and other drivers for response to climate change issues is expected to increase over the next few years. While it is anticipated that water utilities will need to consult program-specific documents and other information sources in development of inventory and management programs, this manual provides the accounting fundamentals and guidance necessary to initiate a management strategy in response to these developments.

CHAPTER 1

PURPOSE OF PROJECT AND REPORT

1.1 INTRODUCTION

This greenhouse gas (GHG) emissions guidance document for water utilities was prepared as part of Water Research Foundation (Foundation) Project 4156. It is intended to assist water utility staff in understanding GHG reporting programs, accounting principles and existing guidelines, and emission estimation methodologies for GHG source types relevant to water supply and treatment and necessary for the preparation of accurate estimates of a utility's GHG impacts. This document also provides a conceptual framework for the development of a GHG management strategy.

The emission estimation guidance provided is further intended to support users in development of an inventory that is compliant with the guidelines and requirements of any of the existing GHG registries and regulatory programs applicable to water utilities based in the United States. Reporting to programs currently under development, such as the U.S. Environmental Protection Agency (USEPA) mandatory GHG reporting rule (in interagency review as of March 2009 and due for final release in June 2009), may also be supported by this guidance. In general, most existing registries and programs are in very close agreement regarding inventory principles and methodology, although some small differences exist. As such, this document does not cover all requirements of all programs, and does not list data such as default GHG emission factors that could change as individual program guidelines are updated. It is therefore strongly recommended that, prior to preparation and submittal of an inventory for a particular reporting registry, users of this document obtain and study the relevant guidelines and protocols.

Most registries require reporting of Scope 1 (direct) and Scope 2 (indirect) GHG emissions. However, water utilities may have significant ability to influence Scope 3 (optional indirect) emissions, including those from upstream and downstream operations or from reduction projects created by the utility in the surrounding community. Given the breadth of Scope 3 emission source types involved, this document presents detailed calculation methodologies only for Scope 1 and Scope 2 emission sources typically found at water utilities. Detailed definitions of the three scopes of GHG emissions are found in Chapter 4.

Another goal of the Foundation Project 4156 was to prepare, if necessary, an estimation protocol specific to water utilities for review and adoption by the relevant registries. As a comparison, wastewater treatment utilities include unique and significant process emission sources of three GHGs: carbon dioxide (CO₂), nitrous oxide (N₂O), and methane (CH₄), and the development of specialty protocols was required to establish an accepted and common basis for reporting. As discussed in Chapter 10, the authors have reviewed all identified Scope 1 and Scope 2 emission sources typical of water utilities and concluded that all are adequately characterized by existing protocols or would be considered *de minimis* in magnitude. Therefore, this document provides guidance on estimating those emissions, but a separate protocol is not proposed.

1.2 THE WATER INDUSTRY AND GREENHOUSE GAS GENERATION

The water industry contributes to GHG emissions primarily through the use of stationary combustion, mobile combustion, and electricity. These three primary sources are affected by characteristics specific to each water utility, including source water location, raw water quality and the treatment required, size of the overall organization, and distribution system topography. These factors, as well as others, contribute to a water utility's baseline GHG emissions inventory.

Regardless of the GHG inventory protocol used, several steps are common when developing a GHG inventory. The following briefly describes the activities, some of which are concurrent, that are required when developing an inventory:

- **Understanding GHG Accounting Fundamentals:** Before beginning an inventory, it is important for a utility to understand the overall goal of the inventory and the mechanics of analysis. An accurate GHG inventory follows five fundamental accounting principles that aid in the development of a sound baseline and subsequent updates. These principles include Relevance, Completeness, Consistency, Transparency, and Accuracy. Utilities also have an opportunity to offset emissions through the use of offset projects, which are explained in Chapter 3 and further discussed in Chapter 11. Concepts regarding project baselining are introduced in Chapter 3, and explained further in Chapter 5.
- **Describing the content of the inventory, and setting utility boundaries:** An entity is described by geographic, organizational, and operational boundaries, which together lay the framework of the inventory. Chapter 4 describes how to set a utility's boundary and the elements of a utility that would contribute to an inventory. Also described in Chapter 4 is the difference between a GHG inventory and a GHG footprint.
- **Defining a utility's data management strategy and systems:** A utility must carefully manage the data used to develop a GHG inventory. Accurate data management is a key technical issue that contributes to a successful baseline and the ongoing tracking of GHG inventory. Chapter 5 describes issues regarding data granularity and management systems, selection of a base year for tracking progress in emission reductions, update of a baseline inventory once created, employee training activities, and finally, considerations regarding the internal or external audits.
- **Understanding inventory issues specific to water utilities:** Water utilities face some unique issues in implementing an effective GHG management strategy, such as incorporating renewable energy and water conservation in a GHG inventory. In addition, it is useful to organize a GHG inventory in a format that is more amenable to benchmarking for a water utility. Therefore, it is recommended to organize GHG data in six categories: Source, Treatment, Distribution, Buildings/Infrastructure, Fleet, and Other. These categories are discussed in Chapter 6.
- **Calculating indirect emissions, direct emissions, and unique emissions:** Chapters 7 through 10 provide example calculations for indirect emissions from electricity use and direct emissions from stationary combustion, mobile sources, and unique emission sources.

- **Identifying management strategies for reducing a GHG inventory:** By understanding the source of GHG emissions and generating a baseline emissions inventory of the organization as a whole, a water utility may be able to identify projects to reduce emissions. Chapter 11 describes some methods available to the water industry to reduce emissions, including the use of offset projects.

1.3 REPORT ORGANIZATION AND CONTENTS

This report is organized into four parts, as described below, followed by a glossary of typical GHG inventory terms, references, and list of abbreviations and acronyms used in the report.

Part I, Introduction, provides a general introduction to the project and a description of existing GHG protocols and quantification tools:

- Chapter 1 – Purpose of Project and Report
- Chapter 2 – Existing Protocols and Quantification Tools

Part II, Designing an Emission Inventory—How to Get Started, describes the basic knowledge and assumptions necessary to develop a GHG emissions inventory, including technical issues that are pertinent to water utilities. In addition, the six sectors recommended for segregating water utility emissions for the purposes of benchmarking and instructive comprehension of the GHG sources are also included:

- Chapter 3 – Accounting Fundamentals
- Chapter 4 – Boundaries
- Chapter 5 – Data Management and Management Systems
- Chapter 6 – Water Utility Issues

Part III, Quantifying Emissions, describes the Scope 1 and Scope 2 emissions, as well as the GHG sources unique to water utilities:

- Chapter 7 – Unique Emissions Calculations
- Chapter 8 – Indirect Emissions from Electricity Use
- Chapter 9 – Direct Emissions from Mobile Combustion
- Chapter 10 – Direct Emissions from Stationary Combustion

Part IV, Management Strategies, explores the opportunities available to water utilities following the development of a baseline for reducing GHG emissions through new projects and modification of typical practices:

- Chapter 11 – Management Strategies

CHAPTER 2

EXISTING PROTOCOLS AND QUANTIFICATION TOOLS

This chapter describes the existing protocols, guidance documents, and calculation tools that are applicable to GHG emission reporting by U.S.-based entities. While the emphasis and primary intent of each guidance document vary, most are relatively consistent in methodology and approach.

Many international and domestic protocols and quantification tools are available for the voluntary accounting and reporting of GHG emissions at the corporate, facility, or municipal level. These protocols and tools may apply to annual sustainability information releases, reporting within voluntary reduction programs, or reporting within mandatory reporting or cap-and-trade programs. While there is no one protocol or tool developed specifically for use by water utilities to quantify entity-wide GHG emissions, the existing protocols, guidance documents, and quantification tools can be used to develop inventory goals and objectives, organizational and operational boundaries, reduction targets, and an entity-wide GHG emission inventory.

During the development of this document, the USEPA has been drafting a mandatory GHG emission reporting rule that will apply economy-wide within the United States and may apply to water utilities. While it is possible that requirements of this rule may differ from existing protocols and standards, it is anticipated that the concepts covered in this guidance document will remain consistent with emerging rules. Additionally, the State of California has passed Assembly Bill 32, which requires the California Environmental Protection Agency, Air Resources Board (CARB) to adopt a statewide greenhouse gas emissions limit equivalent to statewide greenhouse gas emissions levels in 1990 and to be achieved by 2020. In December 2008, the CARB adopted a greenhouse gas scoping plan to achieve this goal through a cap-and-trade program and industry-specific reductions. Preliminary review of CARB's reporting program (CARB 2009) indicates close alignment with existing reporting protocols. Other federal, state, and regional developments in cap-and-trade regulations are not anticipated to fundamentally change the existing GHG emission accounting standards and principles.

The following list of registries, programs, and protocols were referenced as part of this report:

- World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) – The Greenhouse Gas Protocol Initiative
- USEPA – National Greenhouse Gas Inventory
- U.S Department of Energy – Voluntary Reporting of Greenhouse Gases Program [1605(b)]
- The Climate Registry (TCR)
- The California Climate Action Registry (CCAR)
- International Council for Local Environmental Initiatives (ICLEI) – Local Governments for Sustainability
- Chicago Climate Exchange (CCX)
- International Organization for Standardization (ISO)
- United Kingdom Water Industry Research (UKWIR) – Workbook for Quantifying Greenhouse Gas Emissions

A brief synopsis of each is provided, including a matrix (Table 2.1) comparing the registries. Of these registries, quantification examples are provided in this guidance document primarily using protocols from TCR and CCAR. Although the focus of CCAR will shift from that of a registry for entity-wide emissions to that of a registry for GHG offset projects, the quantification examples are still relevant for the purposes of this guidance

Note that this list is not all-encompassing. In particular, guidance and standards for assessment of project-based GHG reductions, and qualification of resulting offsets, such as the Gold Standard and Voluntary Carbon Standard, are not included here. The intent of this synopsis is to identify other programs that provide guidance for the development of entity-wide inventories and that may contain information relevant to quantification methodology for emission source types of relevance to the water industry.

2.1 PROTOCOL AND REGISTRY PROCESS OVERVIEW

In the process of estimating its GHG emissions impact, a water utility begins by estimating the amount of GHGs produced by various sources, including consumption of electricity and type and quantity of fuel burned. Because GHG emissions typically cannot be directly measured, other than for sources such as electric utility boilers that are equipped with continuous emission monitoring systems, the estimation of GHG emissions is calculated through the use of a GHG protocol, several of which are detailed further in this chapter. Once a protocol has been used to quantify GHGs, a water utility may report the GHG emissions in a GHG registry on a voluntary or mandatory basis. Several registries are also described as part of this chapter. Typically, using a registry will require third-party verification of the GHG emissions estimate to guarantee the transparency, rigor, and integrity of the calculations. Additional detail specific to each protocol/registry is included below.

2.2 WORLD RESOURCES INSTITUTE AND WORLD BUSINESS COUNCIL FOR SUSTAINABLE DEVELOPMENT – THE GREENHOUSE GAS PROTOCOL INITIATIVE

The combined effort of the WRI/WBCSD is responsible for creating the internationally accepted protocol for the quantification of GHG emissions: the GHG Protocol (WRI/WBCSD 2004). The majority of domestic and international GHG reporting program protocols are derived from this protocol.

The GHG Protocol is based on five guiding accounting principles: relevance, completeness, consistency, transparency, and accuracy (these principals are more fully discussed in Chapter 3). The Corporate Accounting and Reporting Standards (Standards) portion of the protocol provides the framework for developing a GHG inventory and contains methodologies for both private and public businesses and organizations to inventory and report their GHG emissions. The contents of the Standards are as follows:

Table 2.1
GHG emissions inventory protocol and program summary

Program or Document	Geographic boundaries	Organizational boundaries	<i>de minimis</i>/ materiality	Gases included	Baseline/ base year	Electricity factors	Reduction methods	Certification/ verification	Inventory/ registry	Reductions required	Offset projects acceptable	Trading	Relevant protocols/ guidance
WRI/WBCSD	Worldwide	Financial control; operational control; equity share	5% materiality threshold suggested	Kyoto 6 (Montreal gases optional)	Any single year or multi-year average	USEPA's eGRID; no T&D; average only	Absolute emphasized; intensity	Verification encouraged	Inventory guidelines only, no registry	Yes	Project guidelines only, no registry	No	Cross sector guidance and tools
USEPA Climate Leaders	U.S. (required); foreign (optional)	Financial control; operational control; equity share	No fixed threshold	Kyoto 6	Single year (most recent with available data)	USEPA's eGRID; no T&D; average only	Absolute, intensity, and projects	Verification optional (USEPA desk and field audits)	Yes	Yes	Yes	No	Cross sector guidance and tools
USDOE/EIA 1605(b)	U.S. (required); foreign (optional)	Financial control; operational control; equity share	3%	Kyoto 6 + CFCs (excl. from inventory)	1 to 4 years Register: 2002+ Report: 1990+	EIA state-based regions; T&D; average and fossil	Intensity, absolute, and others	Certification required; verification optional (EIA desk audit)	Yes	Yes	Yes	No	Cross sector guidance and tools
The Climate Registry	U.S., Canada, Mexico	Financial control; operational control; equity share	5%	Years 2008 to 09: CO ₂ Year 2009: Kyoto 6	Single year (first reporting year); optional	USEPA's eGRID (U.S.)	NA	Third-party verification required	Yes	No	Yes	No	Cross sector guidance and tools; Local Government Operations Protocol
California Climate Action Registry	California, other U.S. (optional)	Financial control; operational control; equity share	5%	CO ₂ (Reporting Years 1 to 3) Kyoto 6 (thereafter)	Single year (first reporting year); optional	USEPA's eGRID (U.S.)	NA	Third-party verification required	Yes	No	Yes	No	Cross sector guidance and tools; Local Government Operations Protocol
ICLEI	Worldwide	All methods	No fixed threshold	Kyoto 6	Any single year	Country specific; use of Nationally approved factors recommended	Absolute and projects	Verification encouraged	Inventory guidelines only, no registry	Yes	Yes	No	Local Government GHG Emissions Analysis Protocol; Local Government Operations Protocol
Chicago Climate Exchange	Worldwide	Financial control; operational control; equity share	5%	Kyoto 6	1 or 4 years; 2000 or average of 1998-2001	National average	Absolute	Third-party verification required	Yes	Yes	Yes	Yes	See WRI/WBCSD
ISO 14064	Worldwide	Facilities; financial control; operational control; equity share	No fixed threshold	Kyoto 6	Any single year or multi-year average	No guidance	Projects	Verification guidance provided	Inventory guidelines only, no registry	Quantification only	Project guidelines only, no registry	No	N/A
UKWIR Workbook	United Kingdom	N/A	N/A	Kyoto 6	N/A	Defra Guidelines	N/A	N/A	N/A	N/A	N/A	N/A	Quantification methodology for water and wastewater industry

1. GHG Accounting and Reporting Principles
2. Business Goals and Inventory Design
3. Setting Organizational Boundaries
4. Setting Operational Boundaries
5. Tracking Emissions Over Time (for base year assessment)
6. Identifying and Calculating GHG Emissions
7. Managing Inventory Quality
8. Accounting for GHG Reductions
9. Reporting GHG Emissions
10. Verification of GHG Emissions
11. Setting GHG Targets

Appendices to the Standards provide guidance on accounting for indirect emissions from electricity purchase and accounting for sequestered atmospheric carbon.

The GHG Protocol website also contains Calculation Tools. The tools complement the Standards and assist in quantifying emissions from business activities, but they are not specifically tailored for the water industry. It should be noted that the emission factors included in the Calculation Tools are internationally based; while most likely valid for U.S.-based inventories, factors should be confirmed for any location variations in fuel properties and other factors. The Calculation Tools currently available for use include the following:

- Cross Sector Tools
 - GHG Emissions from Stationary Combustion
 - Indirect CO₂ Emissions from Purchased Electricity, Heat, or Steam
 - CO₂ Emissions from Transport or Mobile Sources
 - Emissions from Employee Commuting
 - Measurement and Estimation Uncertainty for GHG Emissions
 - CO₂ Emissions from Fuel Use in Facilities
 - CO₂ Emissions from Business Travel
 - Allocation of Emissions from a Combined Heat and Power Plant
- Sector-Specific Toolsets
 - Adipic Acid
 - Aluminum
 - Ammonia
 - Cement
 - Hydrochlorofluorocarbon-22 (HCFC-22)
 - Iron and Steel
 - Lime
 - Nitric Acid
 - Pulp and Paper
 - Refrigeration and Air-Conditioning Equipment
 - Semi-Conductor
 - Wood Products
 - All Companies with Offices and the Service-Sector

The GHG Protocol also includes a Project Accounting Protocol and Guidelines for Calculating Reductions in GHG emissions from specific GHG reduction projects and/or climate change mitigation projects. The Project Accounting Protocol contains additional guidance for Land Use, Land-Use Change and Forestry, and Grid-Connected Electricity projects.

The GHG Protocol and Calculation Tools can be accessed at www.ghgprotocol.org.

2.3 USEPA CLIMATE LEADERS/NATIONAL GREENHOUSE GAS INVENTORY

Climate Leaders is a USEPA industry-government partnership that works with companies to develop long-term comprehensive climate change strategies (USEPA 2009). Industry Partners must sign a partnership agreement, set an entity-wide GHG reduction goal, and inventory their GHG emissions to measure progress. The main benefit of the program to Partners is public recognition of their GHG emission reduction activities. By joining the program, Partners identify themselves as environmental leaders and strategically position themselves as climate change policy continues to unfold.

As part of the program, Partners quantify their GHG emissions of the applicable six GHGs (CO₂, CH₄, N₂O, HFCs, perfluorocarbons [PFCs], and sulfur hexafluoride [SF₆]) utilizing the Climate Leaders guidance, report their GHG inventory data, and either provide Inventory Management Plans or optional third-party verification reports of their GHG management process. Partners also set a GHG reduction goal compared to an appropriate base year (post-2000) based on company-specific GHG emission sources and reduction opportunities.

The Climate Leaders Design Principles guidance (USEPA 2005) provides the general GHG accounting and reporting principles that, similar to the WRI/WBCSD GHG Protocol, direct the program. The principles assist Partners in determining organizational and operational boundaries, identifying business goals and objectives, managing inventory quality, and setting a reduction goal. The program also offers cross-sector guidance, which includes information on quantifying emissions from stationary combustion, mobile combustion, electricity and steam usage, and fugitive emissions from air conditioning and refrigeration units. Sector-specific guidance is provided for estimating process emissions from municipal solid waste landfills, the manufacture of refrigeration and air conditioning equipment, and iron and steel production, but is not provided for water utilities. Emission factors for the quantification of direct emissions included in the guidance documents were developed from the USEPA Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (released in 2007). The methods used to quantify emissions within this national inventory are consistent with the methods and approaches of the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (2006). Emission factors for the quantification of indirect emissions are based upon data gathered by the USEPA Emissions & Generation Resource Integrated Database (eGRID2007, v 1.0, as annually updated) (USEPA 2009), a comprehensive inventory of environmental attributes of electric power systems and the USEPA Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005.

The program's inventory guidance documents can be viewed at <http://www.epa.gov/climateleaders/resources/index.html>.

2.4 U.S. DEPARTMENT OF ENERGY – VOLUNTARY REPORTING OF GREENHOUSE GASES PROGRAM [1605(B)]

The “1605(b) Program” developed by the U.S. Department of Energy (DOE) was named after Section 1605 of the Energy Policy Act of 1992 and allows for the voluntary reporting of GHGs through the DOE.

Under the federal 1605(b) Program, U.S.-based companies, entities, municipalities, and/or individuals can record and track their GHG emissions on an intensity or absolute basis, as well as register emission reduction projects. However, the entity must have completed emissions inventories from 1998 through 2001 and report annually under the 1605(b) Program for its projects to be considered for registration. Projects suitable for registration under the 1605(b) Program must reduce or sequester emissions of the six Kyoto Protocol GHGs (CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) and be implemented after the year 2002. Project-based emission reductions may be required to use certain program-specific quantification methods and meet scoring criteria for approval.

The DOE finalized the Technical Guidelines for the program in January 2007 (USDOE 2007). This guidance document contains cross-sector (e.g., mobile combustion, stationary combustion, fugitive emissions, and emissions from purchased electricity, steam, and hot/chilled water) and sector-specific (e.g., various industrial processes, geologic sequestration, agriculture, and forestry) guidelines for the quantification of GHG emissions. The guidelines also assist users with ranking their data, emissions factors, and quantification methods for use in the program’s inventory rating system. It is hoped that by establishing stringent, yet internationally acceptable guidelines for quantifying emission reductions, participants will be able to trade the registered reductions globally in the future.

For more information on the 1605(b) Program and to view the general guidelines, go to www.eia.doe.gov/oiaf/1605/1605b.html.

2.5 THE CLIMATE REGISTRY

TCR was developed to set consistent and transparent standards for the measurement, verification, and public reporting of GHG emissions throughout North America in a single registry. A non-profit organization that supports both voluntary and mandatory reporting programs from various states and some Canadian provinces, TCR is a GHG emissions inventory registry and not a mandatory reduction or cap-and-trade program.

Registry participants must commit to 1) calculate emissions using the TCR General Reporting Protocol (GRP) (2008) and sector/source specific guidance and tools provided; 2) hire an approved third-party contractor to verify their emissions data; and 3) report verified, entity-wide GHG emissions data throughout the U.S., Canada, and Mexico on the TCR website through the Climate Registry Information System (CRIS) (TCR 2009).

TCR’s GRP provides guidance on determining operational and organizational boundaries, and establishing and updating a base year. The GRP contains cross-sector guidelines (e.g., guidelines for mobile combustion, stationary combustion, fugitive emissions, and emissions from purchased electricity, steam, and hot/chilled water) for the quantification of GHG emissions and contains appendices relevant to quantifying emissions for 12 additional sectors (e.g., aluminum production, cement production, iron and steel production, and pulp and paper production).

TCR recently teamed with CCAR, CARB, and ICLEI USA to develop the Local Government Operations Protocol for the quantification and reporting of greenhouse gas emission inventories (ICLEI USA 2008). The Protocol is meant to be a “program neutral” guidance document available for use by any local government engaging in a GHG inventory exercise. It brings together GHG inventory guidance from a number of existing programs and allows all U.S. local governments, regardless of program affiliation, to utilize a single guidance document when developing GHG emissions inventories. ICLEI wants the Protocol to serve as the translation of the International Local Government GHG Emissions Analysis Protocol for use in developing local government operations emissions inventories in the United States.

The Climate Registry General Reporting Protocol can be found at: <http://theclimateregistry.org/protocols.html>.

2.6 CALIFORNIA CLIMATE ACTION REGISTRY

The CCAR is a non-profit public/private partnership that serves as a voluntary GHG registry to encourage and promote early actions to reduce GHG emissions. The purpose of the CCAR is to help companies and organizations with operations in the State of California to establish GHG emissions baselines to which future GHG emission reduction requirements may be applied. CCAR encourages voluntary actions to increase energy efficiency and decrease GHG emissions. CCAR has developed a general reporting protocol (not the same as TCR GRP above) that provides guidance on determining an entity’s operational and organizational boundaries, and establishing and updating a base year. The protocol contains guidance on how to quantify cross-sector emissions (e.g., mobile combustion, stationary combustion, fugitive emissions, and emissions from purchased electricity, steam, and hot/chilled water) and resources for quantifying emissions from various manufacturing processes (e.g., aluminum production, cement production, iron and steel production, pulp and paper production, etc.).

When organizations become participants, they agree to register their GHG emissions for all operations in California, and are encouraged to report nationwide emissions via the Climate Action Registry Reporting Online Tool (CARROT). The State of California, in turn, will 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.

Currently, CCAR requires the reporting of only CO₂ emissions for the first three years of participation, although participants are encouraged to report the remaining five GHGs covered in the Kyoto Protocol. The reporting of all six Kyoto GHGs is required after three years of CCAR participation. Participants are also required to have their emissions inventories certified by a CCAR-approved, third-party verifier at the end of the first year and every third year afterwards.

CCAR launched the Climate Action Reserve (CAR) in 2008 (CCAR 2008b). CAR is a public offset program used for quantifying greenhouse gas emission offset projects. It establishes guidelines for credible emissions reduction projects and provides an online system for tracking qualifying projects and their offset credits, Climate Reserve Tonnes (CRTs). The Voluntary Carbon Standard Association (VCS Association) recently approved the California Climate Action Registry as the first independent greenhouse gas offset program it has recognized (VCS Association 2008b). The VCS Association is an organization that provides a global standard and program for the approval of credible voluntary offsets. The CAR recognition by the VCS Association provides the foundation for the establishment of common global standards for voluntary GHG emission reduction projects and their offsets, which could be significant in unifying international carbon markets. Because of the overlap of missions of CCAR and TCR for

registry of entity-wide GHG emissions, CCAR has begun phasing out this mission to focus its actions on CAR.

Parties interested in CCAR can go to www.climateregistry.org for emissions calculation guidance.

2.7 INTERNATIONAL COUNCIL FOR LOCAL ENVIRONMENTAL INITIATIVES – LOCAL GOVERNMENTS FOR SUSTAINABILITY

Originally started as the International Council for Local Environmental Initiatives, the organization is now an international association of local and regional government organizations that have made a commitment to sustainable development. ICLEI – Local Governments for Sustainability, as it is known, comprises more than 700 cities, towns, and counties worldwide.

ICLEI provides resources, tools, and information exchange services to build capacity, share knowledge, and support local governments in the implementation of sustainable development and reduction of GHG emissions.

In February 2008, ICLEI released a draft of the International Local Government GHG Emissions Analysis Protocol (ICLEI Protocol) (ICLEI 2008). The document is a comprehensive protocol for the accounting and reporting of GHG emissions inventories for domestic and foreign local governments. It provides users with guidance on organizational and operational boundaries, sectors and sources to be included, and emissions quantification methods. In general, this Protocol has structure and content similar to the WRI/WBCSD GHG Protocol. The ICLEI Protocol adds “conservativeness” as a guiding principle (that is, assumptions, values, and procedures used to quantify GHG emission levels should overestimate, not underestimate).

The ICLEI Protocol provides guidance on quantifying direct emissions from stationary combustion, mobile combustion, and fugitive and process-related sources. It also states options for estimating indirect emissions from electricity, steam, and heating/cooling services. The ICLEI Protocol indicates that emissions from wastewater should be determined based on the First Order Decay model developed by the IPCC and described in the 2006 Guidelines for National Greenhouse Gas Inventories.

The ICLEI Protocol guidance allows for using emission factors from various sources (hierarchy as follows):

1. National government agency
2. Sub-national (e.g., regional, state, County)
3. International agency (for example, IPCC)
4. University or other research institute
5. Non-government organization
6. Corporate/industry reports

The tiered approach to rank quantification method complexity is based on emission factors used and activity data gathered; Tier 1 is the basic method; Tier 2, intermediate; and Tier 3, the most accurate/complex. Members are encouraged to use the highest tier possible.

For example, a Tier 1 emission factor is a default emission factor provided by an international organization such as the IPCC. A Tier 2 emission factor is a country-specific emission factor for the source category and fuel used for each GHG emitted. A Tier 3 emission factor would be based on the following:

- Combustion technology
- Operating conditions
- Control technology
- Quality of maintenance
- Age of the equipment used to burn the fuel
- A country-specific emission factor for the source category and fuel for each gas

For activity data used in emissions quantification, tiers are ranked in a similar method. Tier 1 activity data are based on national averages, for example, fuel use or CH₄ recovery per regulatory guidelines. Tier 2 activity data are estimated based upon known parameters such as fuel usage based on vehicle miles traveled, price paid and average fuel costs, or CH₄ recovery based on system design. Tier 3 activity data are based on metered energy use or metered CH₄ recovery.

For ICLEI, multiple tiers are allowed for a county-wide/municipal inventory. The tiers may vary by source.

The ICLEI website does not have quantification tools that are readily available for public use. However, emissions quantification software is provided to all members at no charge.

For more information on ICLEI, visit: www.iclei.org.

2.8 CHICAGO CLIMATE EXCHANGE

The Chicago Climate Exchange (CCX) was established in response to a feasibility study conducted by Environmental Financial Products and funded by the Chicago-based Joyce Foundation. The study concluded that a North American private-sector pilot GHG trading market was feasible. A subsequent grant in August 2001 funded the initiation of research on market implementation. CCX is touted as “North America’s only, and the world’s first, GHG emission registry, reduction and trading system for all six GHGs” (CCX 2008).

As a member of the exchange, CCX members make a voluntary, legally binding commitment to reduce direct GHG emissions below an emissions baseline. By the end of Phase I (December 2006), members’ GHG emissions were required to be 4 percent below their 1998 to 2001 baseline. For Phase I members, Phase II GHG emissions must be reduced 2 percent more by 2010. The emissions reduction target for new Phase II members is 6 percent below the 2000 baseline by 2010. CCX members develop their inventories based upon the WRI/WBCSD GHG Protocol guidance and tools.

Members are encouraged to meet their reduction targets through emission reduction or offset project implementation. Eligible offset projects include landfill and agricultural CH₄ destruction or recovery, carbon sequestration in soils, forestry practices, renewable energy, and other GHG emissions mitigation in the United States, Canada, Mexico, and Brazil. Projects must be reviewed, approved, and registered by CCX for inclusion in the program as an offset project. CCX hires a third party, the Financial Industry Regulatory Authority, for verification of

inventory data, unlike most other registries that require the member to hire an independent third party from a list of pre-certified verification parties.

Once a member's GHG emissions have been quantified and verified, any excess emission reductions can be traded on the Exchange. "Exchange Offsets" are issued after mitigation occurs and required documentation is presented to CCX.

Details on the requirements of this program can be found on the CCX website at www.chicagoclimatex.com.

2.9 INTERNATIONAL ORGANIZATION FOR STANDARDIZATION 14064 STANDARDS

The International Organization for Standardization (ISO) has long been recognized for developing international standards for business, government, and society as a whole. In March 2006, ISO released the ISO 14064 Standard, which comprises three standards:

- ISO 14064-1:2006, Greenhouse gases – Part 1: Specification with guidance at the organization level for the quantification and reporting of GHG emissions and removals.
- ISO 14064-2:2006, Greenhouse gases – Part 2: Specification with guidance at the project level for the quantification, monitoring, and reporting of GHG emission reductions and removal enhancements.
- ISO 14064-3:2006, Greenhouse gases – Part 3: Specification with guidance for the validation and verification of GHG assertions (ISO 2006).

The ISO 14064 Standard was developed to provide government and industry with an integrated set of tools (both accounting and verification) for programs aimed at reducing GHG emissions, as well as for emissions trading. The Standard is offered as "a solution to the problems posed by the fact that governments, business corporations and voluntary initiatives were using a number of approaches to account for organization- and project-level GHG emissions and removals with no generally accepted validation or verification protocols."

ISO 14064-1 contains guidance on inventory design, development of organizational and operational boundaries, quantification methods, emission reductions, establishment of a base year, uncertainty analysis, inventory quality, data management, record retention, reporting of GHG emissions, and preparation for verification similar to the WRI/WBCSD GHG Protocol and USEPA Climate Leaders Design Principles. Appendices to this section of the Standard also include information on indirect emissions, global warming potentials (GWP), and the consolidation of facility-level data. There are no quantification tools included as part of this Standard. As noted in the descriptions above, ISO 14064-2 focuses on quantification of reduction or offset-producing projects, and ISO 14064-3 provided guidelines for external verification of inventories produced by others.

The ISO standards can be purchased at www.iso.org.

2.10 UNITED KINGDOM WATER INDUSTRY RESEARCH – WORKBOOK FOR QUANTIFYING GREENHOUSE GAS EMISSIONS

The UKWIR *Workbook for Quantifying Greenhouse Gas Emissions* (Workbook) was finalized in February 2005. Developed in response to the government's adherence to the Kyoto Protocol-limited emission of GHGs to 1990 levels, the project's objective was to "...achieve a universally accepted, standardized approach in which companies could have confidence, for use (for example) in producing Corporate Environmental Reports (CERs), and in benchmarking" (UKWIR 2005). The project was focused specifically on estimating individual water company GHG emissions.

The Workbook addresses emissions from UK water and sewage operations, including the following:

- Drinking water treatment and pumping
- Sewage treatment and pumping
- Sludge treatment and disposal
- Administrative activities
- Transport
- Use of purchased electricity
- Production and use of self-generated electricity from biogas, sludge, or other fuels
- Fuel use, including use in process and transport

For each activity, output estimates were provided for total GWP arising in accordance with the Kyoto Protocol and carbon of a non-fossil origin. The approach was promulgated in a Microsoft Excel spreadsheet tool.

The Workbook was developed after review and comparison to protocols and methodologies current at that time. The 2004 UK Department for Environment, Food, and Rural Affairs (Defra) Guidelines for Company Reporting were used where possible as the official guidance document and were extended to cover water industry activities where necessary (UKWIR 2005). Emissions factors used were from the Defra Guidelines exclusively or from industry standards where the Defra Guidelines were not explicit.

Note that UKWIR has also more recently produced its *Carbon Accounting in the UK Water Industry: Guidelines for Dealing with 'Embodied Carbon' and Whole Life Carbon Accounting* (UKWIR 2008). The document provides guidelines for United Kingdom water companies in their carbon emissions estimation and costing for asset planning. It builds on the previous guidance for operational carbon emissions by adding a framework to estimate embodied carbon in construction and for combining that with whole life carbon accounting associated with operations.

More information regarding the UKWIR Workbook and other relevant references, such as the embodied and whole life carbon accounting reference can be found at <http://www.ukwir.org/site/web/content/home>.

CHAPTER 3 ACCOUNTING FUNDAMENTALS

This chapter presents fundamental concepts for GHG accounting and covers the accounting principles, types of GHGs, the concept of global warming potential, source categories, *de minimis* sources, absolute versus intensity-based reporting, and basics of carbon offsets. This chapter also provides a brief summary of how to report a utility's emissions.

It is recommended that the decisions and procedures discussed in this section be documented to ensure consistency in inventory development if responsible staff changes and to document the management plan to outside parties. Third-party verifiers under TCR, for example, will require documentation as part of the review process. It is further recommended that all such information be compiled into a single document or collection of documents that comprise a formal Inventory Management Plan.

3.1 ACCOUNTING PRINCIPLES

Most of the protocols and guidance documents are based on the five fundamental accounting principles of Relevance, Completeness, Consistency, Transparency, and Accuracy. TCR addresses these items by encouraging users to do the following:

- **Relevance:** Ensure that the GHG inventory appropriately reflects the GHG emissions and serves the decision-making needs of users—both internal and external to the organization.
- **Completeness:** Account for and report all GHG emission sources and activities within the defined inventory boundary.
- **Consistency:** Use consistent methodologies to allow for meaningful comparisons of emissions over time. Clearly document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.
- **Transparency:** Address all relevant issues in a factual and coherent manner based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.
- **Accuracy:** Ensure that the quantification of GHG emissions is neither systematically overstating or understating your true emissions, and that uncertainties are reduced as much as practicable. Achieve sufficient accuracy to enable users of your data to make decisions with reasonable assurance of the integrity of the reported information (reference).

Other guidance, such as that from ICLEI, also suggests conservativeness: where uncertainty exists, assumptions, values, and procedures used to quantify GHG emission levels should overestimate entity-wide emission estimates and underestimate project-based reductions (ICLEI 2008).

3.2 GREENHOUSE GASES TO BE REPORTED

As established by the Kyoto Protocol, developed by the United Nations Framework Convention on Climate Change (UNFCCC) and brought into force in February 2005, there are six GHGs or categories of GHGs that must typically be included in an emissions inventory (United Nations 1998):

1. Carbon Dioxide (CO₂)
2. Methane (CH₄)
3. Nitrous Oxide (N₂O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur Hexafluoride (SF₆)

An entity should evaluate its operations for sources that emit, utilize, or produce materials that contain these gases and document the gases that are and are not included in the inventory. If a gas is not included in the inventory, the rationale should be documented as to why not.

Other gases are GHGs, but they are typically not included in emission inventories. Most significantly, chlorofluorocarbons (CFCs) and hydrochloro-fluorocarbons (HCFCs) are potent GHGs, but they were not included in the Kyoto Protocol due to existing regulation of these compounds as ozone depleting chemicals (ODCs) in the Montreal Protocol. Water vapor and ozone are two additional GHGs for which impacts are not typically included in emission inventories.

3.3 GLOBAL WARMING POTENTIAL ESTIMATES

GWP represents the heat-trapping ability of each GHG relative to CO₂. For example, on a unit mass basis, CH₄ has approximately 25 times more ability to trap heat in the atmosphere than CO₂. Hence, the GWP of CH₄ is 25. Halogenated compounds such as the HFCs and PFCs are much more potent GHGs, primarily due to their long atmospheric lifetime, and thus have very high GWP.

GWP estimates have been periodically updated primarily due to changes in global concentrations and atmospheric lifetime of CO₂. Because CO₂ is used as the reference for the other compounds, changes to the estimated heat-trapping potential of CO₂ due to changes in estimates of sinks or sources result in changes to GWP of other compounds. IPCC is the primary reference for GWP data, and it has published relevant updates in the Second Assessment Report (SAR), Third Assessment Report (TAR) and Fourth Assessment Report (AR4). These values are listed in Table 3.1.

Before GHG emissions are reported, tons of each gas must be converted to carbon dioxide equivalent (CO₂-e) using the 100-year GWP values. Thus, based on the GWP data in the SAR, one ton of CH₄ is equivalent to approximately 21 tons of CO₂-e (IPCC 1995).

The choice of SAR, TAR, or AR4 values for GWP may depend on the particular registry program to which an inventory will be reported.

Table 3.1 summarizes the GWP for the six categories of reportable gases.

Table 3.1
Global warming potential estimates

Common Name	Formula	Refrigerant	GWP (100-year)		
			SAR	TAR	AR4
Carbon Dioxide	CO ₂	CO ₂	1	1	1
Methane	CH ₄	CH ₄	21	23	25
Nitrous Oxide	N ₂ O	N ₂ O	310	296	298
Sulfur Hexafluoride	SF ₆	SF ₆	23,900	22,200	22,800
Hydrofluorocarbons					
HFC-23	CHF ₃	R-23	11,700	12,000	14,800
HFC-32	CH ₂ F ₂	R-32	650	550	675
HFC-43-10mee	CF ₃ CHFCHF ₂ CF ₃	R-43	1,300	1,500	1,640
HFC-125	CHF ₂ CF ₃	R-125	2,800	3,400	3,500
HFC-134a	CH ₂ FCF ₃	R-134a	1,300	1,300	1,430
HFC-143a	CH ₃ CF ₃	R-143a	3,800	4,300	4,470
HFC-152a	CH ₃ CHF ₂	R-152a	140	120	124
HFC-227ea	CF ₃ CHF ₂ CF ₃	HFC-227ea	2,900	3,500	3,220
HFC-236fa	CF ₃ CH ₂ CF ₃	HFC-236fa	6,300	9,400	9,810
HFC-245fa	CHF ₂ CH ₂ CF ₃	HFC-245fa	NA	950	1,030
HFC-365mfc	CH ₃ CF ₂ CH ₂ CF ₃	HFC-365mfc	NA	890	794
Perfluorocarbons					
Perfluoromethane	CF ₄	PFC-14	6,500	5,700	7,390
Perfluoroethane	C ₂ F ₆	PFC-116	9,200	11,900	12,200
Perfluoropropane	C ₃ F ₈	PFC- 218	7,000	8,600	8,830
Perfluorobutane (FC 3-1-10)	C ₄ F ₁₀	PFC-3-1-10	7,000	8,600	8,860
Perfluorocyclobutane	c-C ₄ F ₈	PFC-c318	8,700	10,000	10,300
Perfluoropentane	C ₅ F ₁₂	PFC-4-1-12	7,500	8,900	9,160
Perfluorohexane (FC 5-1-14)	C ₆ F ₁₄	PFC-5-1-14	7,400	9,000	9,300

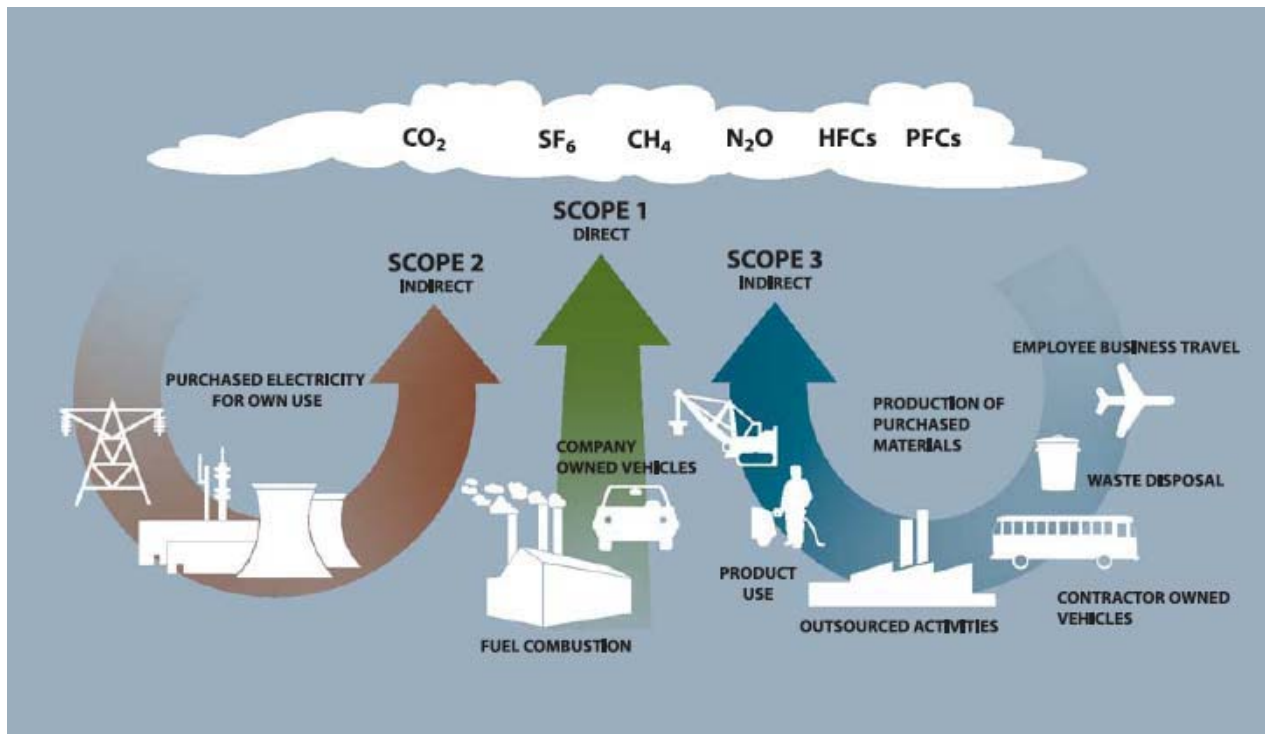
Source: Intergovernmental Panel on Climate Change, Second Assessment Report (1995), Third Assessment Report (2001), and AR₄ (2007)

3.4 EMISSION SOURCE CATEGORIES

The internationally recognized WRI/WBCSD GHG Protocol has identified three scopes of emission sources for categorizing emissions: Scope 1 (direct), Scope 2 (indirect), and Scope 3 (optional indirect) (WRI/WBCSD 2004). Most other protocols follow the same convention, although terminology may vary. Definitions and descriptions of the three emission scopes are provided below, and illustrated in Figure 3.1.

3.4.1 Scope 1 – Direct Emission Sources

Direct emission sources are those sources within the organizational boundary that the entity owns or controls. This source category is divided into four subcategories: stationary combustion, mobile combustion, process-related emissions, and fugitive emission sources.



Source: WRI/WBCSD 2004

Figure 3.1 Overview of emissions, scopes, and sources

Stationary Combustion Sources

Stationary combustion sources are those non-moving or fixed location pieces of equipment that combust fuels to produce steam, heat, power, or electricity at facilities within the organizational boundaries. Such equipment includes, for example, boilers, heaters, turbines, and compressors.

Mobile Combustion Sources

Mobile combustion sources include movable equipment and/or transportation vehicles/vessels that combust fuels to operate. Mobile sources include cars, trucks, marine and aerial vessels, construction and maintenance vehicles, and other non-road vehicles used within an entity's operations.

Process-Related Emission Sources

Process-related emission sources are the result of physical and/or chemical processes other than fuel combustion that take place within the entity's operations. These processes may include the manufacture of a product, processing of materials, or further processing of byproducts. For example, production of ozone results in process-related emissions of N₂O, although as discussed in Chapter 10 these emissions are of minor consequence. For wastewater treatment plants, methane production from anaerobic processes would be considered a process-related emission.

Fugitive Emission Sources

Fugitive sources of emissions result from the intentional or unintentional release of emissions from stationary equipment from points other than “stacks” or exhaust pipes. Most notable are releases of HFCs from refrigerant usage within cooling systems and/or SF₆ from high-voltage electrical transmission and distribution equipment. Also quite significant for some organizations may be the release of CH₄ from natural gas pipeline leaks; emissions from anaerobic wastewater treatment surfaces (if not collected and vented through a pipe) or sludge or manure piles; and livestock enteric fermentation. Chapter 10 provides information on estimation of CH₄ emissions from water storage reservoirs and sludge management.

3.4.2 Scope 2 – Indirect Emission Sources

Indirect emissions included under Scope 2 are those emissions occurring outside of the organizational boundary of the entity from the production of electricity, steam, and/or hot/chilled water for use by facilities within the entity’s organizational boundary. No other non-owned sources of emissions should be included in this category.

Note that all Scope 2 emissions are, by intent, double-counted. The entity generating the electric power (or steam or hot/chilled water) includes the associated emissions in its Scope 1 inventory. The consumer of the power includes its fraction of the same emissions in its Scope 2 inventory. The primary motivation for this is recognition of the fact that the consumer of the power holds the greatest influence over the quantity of power needed. Regulated electric utilities are required by law to “keep the lights on”; as such, while they have some control over the methods of electricity generation and thus the GHG intensity of that power, they have less control over the amount of power required to be generated. Therefore, most programs require quantification of Scope 2 emissions by power consumers to provide incentives for energy conservation.

3.4.3 Scope 3 – Optional Indirect Emission Sources

Optional indirect emissions include emissions over which an entity exerts significant control or influence and that occur within its boundaries. The major source of Scope 3 emissions are upstream and downstream activities, or contracted services such as raw material transport, waste removal and disposal, product transport, or landscaping. Stationary, mobile, process, and/or fugitive source emissions could be generated from equipment, vehicles, and/or processes operated by third-party vendors or suppliers performing services for the entity. Other indirect emissions also include vehicle emissions from employees commuting to and from work and/or traveling for business purposes.

3.5 DE MINIMIS EMISSIONS

The expression *de minimis* is of Latin origin meaning, “of little importance” or “at a level that is too small to be concerned with.” For GHG inventory reporting, *de minimis* is used to reference sources within the inventory that are small and/or negligible in comparison to the overall inventory and for which rigorous supporting data and documentation may not be

warranted. However, to assess whether a source or source category's emissions are *de minimis*, the emissions must first be estimated.

Most protocols require that all emission sources, however small, within an entity's defined boundaries be included in the inventory, but typically allow a lower standard of data quality to support the estimate. Thus, a threshold for what is considered *de minimis* should be set by the entity based on review of program-specific guidance. Thresholds usually range from 3 to 5 percent, meaning that total emissions from a given source or source category will be considered *de minimis* if they are less than or equal to the threshold when compared to the overall emissions total. Based on preliminary analysis, the authors believe that most or all of the unique emissions sources identified within Chapter 10 of this guidance will fall into the *de minimis* category.

The CCAR specifies a 5 percent threshold for *de minimis* emissions. Where the sum of all sources deemed *de minimis* total less than 5 percent of the total reported GHG emissions, the rigorous quantification methodologies specified in the guidance are not required. Furthermore, as long as operations do not change significantly, the estimate needs to be updated only once every three years. The intent of this policy is to avoid burdensome and cost-ineffective reporting requirements. TCR's General Reporting Protocol specifies requirements that it deems "...similar to the *de minimis* concept used by other GHG registries and programs." It allows the use of alternative, simplified estimation methods for any combination of emission sources that total less than 5 percent of the entity's total Scope 1 and Scope 2 emissions. Again, the rationale is to avoid impractical or inefficient reporting requirements.

Regardless of the requirements and terminology of the particular reporting program, it is important that reasonable effort be used to identify and quantify all emissions to the extent reasonably possible, and that the estimates be documented. However, once such emissions are documented, a significant data management burden can be eliminated.

3.6 ABSOLUTE VS. INTENSITY-BASED EMISSION ESTIMATES

After a GHG emissions inventory has been completed, emissions can be reported on one of two bases: absolute or intensity-based. The requirements of the reporting program or registry, and the specific management goals of the entity, will determine the basis for reporting.

3.6.1 Absolute Emissions

Absolute emissions are simply the sum of emissions from all sources identified within the organizational and operational boundaries. (More information on boundaries is provided in Chapter 4.) If reporting direct emissions only, an entity should sum all CO₂-e emissions (both CO₂ and non-CO₂ gases) from stationary combustion sources, mobile combustion sources, processes, and fugitive sources. This consolidated value represents the total actual emissions from the entity. If Scope 2 and 3 emissions are to be included, emissions from these categories must also be expressed as CO₂-e for all sources included. The Scope 2 and 3 totals should be added to the Scope 1 total for reporting.

3.6.2 Intensity-Based Emissions

Intensity-based emissions are expressed as a ratio of absolute GHG emissions per unit of production activity or economic output. This unit of activity is usually a metric relevant to the core business activities of the entity and includes such measures as throughput, revenue, or units produced. This metric is also referred to as a normalization factor. Example normalization factors are pounds of material produced, miles traveled, volume of water treated annually, and total population served. The normalization factor should be chosen based on the way in which the entity chooses to report the emissions data or track progress toward a reduction goal. In general, intensity-based emissions can be defined using the equation below:

$$\text{Intensity-based emissions} = \frac{\text{Annual absolute ton CO}_2\text{-e}}{\text{Total annual normalization metric}}$$

Entities with diversified business lines may find it more relevant to report on an intensity basis to understand the relationship between the GHG emissions emitted and the products produced, or for meaningful comparisons between similar products or processes. Furthermore, some organizations that are projecting growth in throughput, revenue, or production over a period of time, but plan to reduce the GHGs emitted from their processes overall, may also report on an intensity basis. As such, as throughput increases and GHG emissions increase, the overall intensity of emissions may decrease or remain the same. It is possible for GHG intensity to decrease while absolute emissions continue to increase.

3.7 OFFSET PROJECTS

This section presents basic concepts regarding the way in which projects resulting in carbon offsets are evaluated. Additional detail on the types of projects that may result in offsets, where offsets may be acquired, and how they may factor into a climate change management strategy is presented in Chapter 11.

Carbon offsets are tradable commodities typically representing the reduction or sequestration of one metric ton of CO₂-e. Quality and value of offsets may vary tremendously based on the type of project, care taken during quantification and monitoring of project impacts, and programs by which offsets are registered and certified.

Offsets may be categorized as compliance-based or voluntary instruments. Compliance-based offsets are certified for use in satisfying an entity's obligations under a cap-and-trade program. Most notably, a robust international trading market exists for Certified Emission Reductions (CERs) in the Kyoto Protocol Clean Development Mechanism (CDM), whereby entities in developed countries can invest in projects occurring in developing countries.

Because federal, state, and regional cap-and-trade programs are still developing in the United States, most carbon offsets currently traded in this country are voluntary or "over-the-counter" instruments.

For both compliance and voluntary offsets, the guiding theory is that these markets guide the investment of resources toward the most cost-effective GHG reduction options. As such, the offset markets can provide for the development of projects that otherwise would not have adequate economic payback or that are located in parts of the world where sufficient technical and economic capability does not exist to create reductions.

Carbon offsets may be relevant to water utilities in two ways. First, if a utility is able to create reductions in its own emissions, and those reductions are either created prior to implementation of a cap-and-trade program or are additional to the utility's obligations under a future cap-and-trade program, then the utility may have offsets to sell on the voluntary or compliance markets. Second, and perhaps more significantly, a utility may wish to invest in actions outside of its boundaries to create reductions. These reductions or credits can then be applied to the utility's inventory to approach brokers or registries for purchase of projects already developed.

3.7.1 Establishing a Baseline

All reduction projects are evaluated against a baseline scenario, which is defined as the emissions that would have occurred if not for the project. In some cases, such as for a geologic sequestration project, the baseline may be easy to define as zero net emissions or sequestration of emissions. In other cases, a static baseline may be defined, where it is assumed that operations and emissions of the source in question would have continued unchanged into the future.

In most cases, a dynamic baseline is relevant, where it is recognized that changes to operations would have occurred even without the project. For example, consider an investment in an energy efficiency project for a water utility distribution system where population served is growing. Because of the increased population, baseline energy requirements would be expected to increase without the project. The project impacts for future years would be calculated as actual emissions versus the assumed baseline scenario, or the emissions from energy use to serve the larger population given the more efficient systems, minus the calculated emission from energy use to serve the larger population using the original technology.

3.7.2 Understanding Additionality Issues

Not all projects or actions that cause the reduction of GHG emissions or sequestration of carbon will result in carbon offsets. As noted above, the theory behind the carbon markets is to drive projects that otherwise would not have occurred. Thus strict documentation of the additionality of the project will typically be required.

In general, the additionality tests can be divided into the three categories listed below. The specific terminology used here is based on the Voluntary Carbon Standard (VCS) (VCS Association 2008a).

- Regulatory Surplus – the project must not be required by any law, regulation, environmental permit, or legal action (e.g., consent decree).
- Implementation Barriers – the project must face at least one implementation barrier, which would include investment barriers, technological barriers, or institutional barriers. An investment barrier would include capital or investment return constraints that carbon offset revenue would help overcome. A technological barrier relates to the need for development of new technology solutions. Institutional barriers include financial, organizational, cultural, or social barriers that carbon offset revenue will help to overcome.

- Common Practice – the project should not be common practice in its sector or region, compared to other projects that did not achieve the benefits of carbon finance, unless it can be demonstrated that unique barriers existed.

On an international basis, it is clear that investors and authorities have been much more selective in recent years regarding the type of projects that pass the barrier tests. Similar rigor can be expected in future U.S. compliance markets. For the existing U.S. markets, the Voluntary Carbon Standard provides additional detail and explanation of these concepts (VCS Association 2008a).

3.7.3 Uncertainty Regarding Project Eligibility

Because there are a number of voluntary and mandatory regulatory reporting programs and a developing cap-and-trade system available in the United States, there is a level of uncertainty associated with completing offset projects prior to a federally mandated program or cap-and-trade system becoming effective.

An entity should verify the eligibility of an offset project in the program in which it is participating prior to implementation. Projects that are eligible for registration in state, regional, or international programs such as the CCX, the Regional Greenhouse Gas Initiative, UNFCCC Clean Development Mechanism, or UNFCCC Joint Implementation process should be considered first. Because those types of projects are currently being used to meet mandatory reduction requirements, the potential for inclusion in future cap-and-trade programs is likely. Offset projects that have credible methodologies for evaluating effectiveness and, ultimately, the resulting emission reductions should also be considered for implementation. Standardized and internationally acceptable methods for evaluating offset projects lend their credibility and potential eligibility in future cap-and-trade initiatives. The USEPA has developed accounting methodologies for several types of offset projects as part of the Climate Leaders program. These protocols can be viewed on the Climate Leaders website: <http://www.epa.gov/climateleaders/resources/optional-module.html> (USEPA 2005).

3.7.4 Ownership of Offset Credits

Another issue to be evaluated when implementing an offset project is the matter of ownership. Offset projects by definition usually include at least two parties: the investor or developer, and the owner of the land or facility where the reduction is being created. Clear contractual definition of the ownership of the offsets should exist prior to project implementation, and procedures must be used to verify that no other party claims or attempts to trade the same offset after the fact.

Ownership becomes more complicated when reduction of indirect electrical emissions is involved. One example relevant to a water utility is a conservation project that reduces the upstream supply of water by another entity. Note that a reduction to the utility's emissions will probably also occur, but the upstream impact is relevant to this discussion. In this case, three parties could be construed as owners of the reduction or offsets: the water utility, the upstream water supply entity, or the electric utility actually emitting the GHGs from generation of the power used to move the water.

Providing clear answers to all ownership questions is beyond the scope of this document. Users should recognize that ownership is a real issue with carbon reduction projects, and guidance of the reporting or regulatory program, assistance from experienced carbon brokers or registry staff, or legal counsel may be prudent.

3.8 SUMMARIZING A UTILITY'S EMISSIONS

Once the GHG inventory has been completed by quantifying emissions, there are varying ways by which an entity can summarize and report the results. The manner in which the data are aggregated will primarily be dependent on how the data will be used or the registry to which the data will be reported. Similarly, reporting emissions is a function of the particular registry used. Two methods for summarizing data are examined below; a description of the recommended emissions organization is detailed in Chapter 6.

3.8.1 Summation of Emissions for Program and/or Registry Reporting

Depending on the reporting program and/or registry being used, a water utility may be required to summarize GHG emissions at the entity level by category (Direct, Indirect, and Other Indirect), by emission source type (stationary, mobile, process, fugitive), by gas (CO₂, N₂O, CH₄, etc.), or as carbon dioxide equivalent (CO₂-e), as well as the overall emissions total. This method of summation allows the overall emissions to be viewed by category and the magnitude of one source compared against another. This approach is helpful if a utility is trying to determine the greatest source of emissions.

This approach can be used both at the facility or operations level. The summation would allow the utility to meaningfully compare the emissions from one facility to another. Comparisons could be made based upon the size, location, operations, fuel usage, or energy usage of the facilities. Comparisons such as these may be helpful for a utility that is attempting to identify emission reduction opportunities and identify those facilities that might offer the most reductions within prescribed economic parameters.

For most reporting programs and registries, GHG emissions are summed at the facility level and consolidated to the entity level by emission source type, emissions category, gas, and as CO₂-e. A utility should understand the reporting requirements of any program and/or registry in which it participates prior to summarizing emissions.

TCR uses its CRIS to report and aggregate emissions. According to TCR's General Reporting Protocol, entities reporting emissions may use CRIS to assemble an emissions inventory from the ground up by using the automatic calculation functions in CRIS to enter activity-level data for facilities or pre-calculated facility-level data by emissions type (TCR 2009).

3.8.2 Summation of Emissions for Benchmarking Against Similar Entities

When comparing emission totals for benchmarking purposes, a water utility may sum emissions by facility type (source, treatment, distribution, buildings/infrastructure, fleet, and other), emission source type (stationary equipment vs. generators, mobile fleet vs. handling equipment, electricity usage for offices vs. electricity usage for transfer pumps, etc.), source

category (direct, indirect, and other indirect), or as CO₂-e. The basis of the summary should be directly related to how the summary will be used.

Benchmarking, or determining performance metrics for a water utility, offers information about the utility's direct and indirect emissions relative to a unit of water produced. TCR recommends entities benchmark performance in terms of intensity, or a ratio of GHG emissions per economic unit. In the case of water utilities, an example of an appropriate intensity might be metric tons of CO₂ equivalent per 1,000 gallons produced. TCR does not currently mandate the reporting of performance metrics. However, in the future, it may develop and require the reporting of sector-specific performance metrics. It is unknown whether this requirement will pertain to water utilities.

According to TCR, performance metrics serve a range of objectives, including the following:

- Evaluation of emissions over time in relation to targets or industry benchmarks
- Facilitation of comparisons between similar businesses, processes, or products
- Improving public understanding of an entity's emissions profile over time, even as the business activity changes, expands, or decreases

In general, direct comparison of GHG inventories by source categories among multiple utilities can be problematic. Each utility faces its own GHG inventory challenges. For example, varying source water qualities impact the type of treatment required, which in turn impacts the direct and indirect emissions associated with electricity generation and/or usage. A utility that is required to use membranes will have more GHG emissions than a utility that relies on direct filtration methods, unless the utility purchases electricity produced by a renewable energy such as wind or solar. Similarly, a comparison of the distribution source category should take into account the distribution system's physical layout and number of pressure zones. Therefore, any comparison between utilities must be made with recognition of the varied factors affecting the total. Typical benchmarks for various source categories were not estimated as part of this report.

Internal benchmarking, as opposed to comparative benchmarking, may actually be more relevant to a utility, especially if efforts are being made to reduce the GHG inventory. By benchmarking a source category, a utility would be able to identify where efforts can be applied to reduce emissions. Subsequent inventories would identify actual reductions.

CHAPTER 4 BOUNDARIES

The first step in completing a GHG emissions inventory is determining the content of the inventory. Setting geographic, organizational, and operational boundaries for a water utility lays the framework for the inventory. A utility's inventory, however, differs from a utility's footprint. These concepts are described below.

4.1 DEFINING AN ENTITY

An entity is first defined by its geographic and organizational boundaries as described below.

4.1.1 Geographic Boundaries

Where entities are responsible for emission sources crossing political boundaries such as international or state borders, the geographic boundaries of the GHG inventory should be considered. For many water utilities, definition of geographic boundaries will be clear cut, assuming that all of their operations are located in one state. In some cases regional, state, or local reporting initiatives may determine the geographic boundaries of an inventory.

4.1.2 Organizational Boundaries

The next step in developing an GHG inventory is determining the organizational boundaries. For relatively small or simple entities where all facilities and equipment are both 100 percent owned and controlled by the reporting entity, organizational boundaries may be quite clear. Where joint ownership or leases of facilities or operations are involved, or in situations where owned equipment is being operated by others, more care in definition of boundaries may be warranted.

In most of the protocols and guidance documents noted in Chapter 2, there are two approaches for definition of organizational boundaries: Equity Share and Control. For the Equity Share Approach, inclusion of an operation in the inventory is primarily determined by financial ownership. For the Control Approach, an entity must determine whether control is based on operational or financial control of the asset. The two approaches are explained below.

Equity Share

Under the Equity Share Approach, an entity would report all GHG emissions from sources wholly-owned, partially owned, or operated by the entity based upon the percentage of equity held within each asset.

Control

Under the Control Approach, an entity would report 100 percent of all GHG emissions from sources that are under the entity's control—including both wholly owned and partially owned assets. When using the Control Approach, an entity must choose either the financial or operational control approach as defined below:

Financial Control. The decision to use financial control should be based upon the same procedures employed in an entity’s financial accounting process. An entity has financial control if it directs the financial policies of the asset.

Operational Control. The decision to use operational control should be based upon the same procedures employed in an entity’s operating policy. An entity has operational control if it has full authority over the operational policies (both operating policies and health, safety, and environmental policies) of the asset or holds the operating license.

The determination of the reporting approach is vitally important for water cooperatives in which the operations and assets are governed by multiple jurisdictions and financial control may be split among all parties. Entities are encouraged to report using both approaches to ensure assets are not missed in the overall evaluation.

A guide for understanding how these approaches relate to emissions reporting is included in Table 4.1. Note that the 10 percent and 90 percent figures shown are for illustrative purposes only, and have no other significance.

It is recommended that a water utility develop a list of all assets (including buildings, vehicles, equipment, facilities, and so on) included in the inventory and note the percent equity or type of control the entity has in each asset.

A number of cap-and-trade proposals have been introduced to Congress in recent years. It is unknown at this time as to the extent of industry types that will be included in such regulations and whether allocations will be based on equity or control approaches. It is likely that allowance caps will be determined on a per-facility basis, not a per-entity basis, thus making the boundary approach a moot point within the regulatory program; however organizations will still have needs to determine boundaries based on their contractual obligations as owners or operators for covering the costs of allowance and offset management. Where differences exist between the two approaches for a particular entity, it is perhaps the safest course of action to collect information and estimate emissions using both approaches, although this may increase the labor effort required to accomplish the inventory.

**Table 4.1
GHG reporting based on approach**

Approach			
Equity Share		Control	
Percent ownership	Percentage of emissions to report	Level of control*	Percentage of emissions to report
Wholly owned	100%	Wholly owned	100%
90% owned, with or without control	90%	Financial control or holds a financial or capital lease/license	100%
10% owned, with or without control	10%	No financial control	0%
Joint venture and subsidiaries	Based on equity share	Operational control or holds operating lease/license	100%
		No operational control	0%

**Partially owned assets, subsidiaries, and joint ventures should be evaluated using this approach*

4.2 OPERATIONAL BOUNDARIES

An entity's operational boundaries should also be determined prior to developing a GHG inventory. Operational boundaries determine the type of emission sources to be included (whether they are Scope 1, 2, or 3) and the GHGs to be reported. Guidance on evaluating these two key components is included in the following subsections.

4.2.1 Identification of Emission Sources

Definitions of Scope 1, 2, and 3 emission sources are provided in Chapter 3. This section discussed procedures for maintaining a complete and accurate list of such sources.

For the evaluation of operational boundaries, utility staff should develop a systematic process to identify all Scope 1 emission sources located at facilities that are identified as within the organizational boundaries. This process may include interviews of management, operations, and engineering personnel. Review of facility air permits is also a good source of information, as many sources of GHG emissions are also sources of criteria or hazardous air pollutants and are thus identified in the permits. It is also recommended that a process be developed whereby all construction or maintenance projects that add or modify equipment be brought to the attention of the GHG inventory manager so that these changes can be reviewed for their impact on the inventory.

Identification of Scope 2 emissions is a straightforward process. Any electricity generated onsite would be a Scope 1 emission, not Scope 2; thus, the Scope 2 source review is primarily limited to ensuring that all sources of external electricity purchase are identified. Checks of chilled water, hot water, or steam purchases from outside parties should be made, but this will not typically be an issue for water utilities.

As noted previously, inclusion of Scope 3 emission sources is typically optional, and wide latitude exists as to what types of Scope 3 emissions will be included. Often, entities will include no Scope 3 emissions unless there are sources for which significant influence may be possible. For example, a utility may wish to quantify the indirect impacts of upstream water suppliers if options exist for source water supply and the utility's decisions could reduce those Scope 3 emissions. Another example may be the water consumer's use of energy for heating and pumping water if the utility has a demand-side conservation program intended to reduce water consumption. Life-cycle impacts of chemical raw material supplies may also be considered if alternatives exist that may allow reduction of those impacts.

4.3.2 Identification of Gases to be Reported

After the emission sources have been identified, the gases to be reported can be determined. At a minimum, CO₂ emissions will be included for every source category.

For Scope 1 direct emissions, CH₄ and N₂O emissions will be included for stationary and mobile combustion sources. The gases being generated within processes will vary. Emissions of CO₂, CH₄, N₂O, HFCs, and PFCs should be evaluated by process or operations experts. Fugitive emission sources mainly emit HFCs, PFCs, and SF₆. Emissions of these gases from processes, equipment, or storage areas also should be evaluated by process or operations experts.

Scope 2 indirect emissions are solely based on purchased utilities: electricity, steam, and/or hot/chilled water. As a consequence, there will be emissions of CO₂, CH₄, and N₂O resulting from stationary combustion of fuels associated with production of these utilities.

Because the extent of Scope 3 optional indirect emission sources will vary by entity, the type of gases being emitted from these third parties or out-sourced activities will also vary. Given that most of the upstream and downstream activities will fall under a direct or indirect category, the potential exists for any of the six reportable GHGs to be emitted from performing these activities.

Table 4.2 summarizes the gases to be reported by emission source type.

4.3 INVENTORY VERSUS FOOTPRINT

Significant interest has been generated in the environmental community in recent years regarding the value of life-cycle analyses of GHG emission and other environmental impacts. For example, many consumer product manufacturers are beginning to analyze and report the total “cradle-to-grave” impacts of raw material extraction and transport, product manufacture, product distribution and use, and disposal/reuse/recycling. Other entities such as water utilities are using similar analyses to determine the benefits and tradeoffs of various options for water supply sources, treatment process selection, treatment and distribution system design, and so on.

The term “footprint” has been used widely within the GHG management community, and no common definition or use of the term exists. For the purpose of this document and to assist water utilities in management strategy development, the term is used to indicate the total life-cycle GHG impacts of water supply, transport, treatment, and use.

Table 4.2
Summary of greenhouse gases by emission source

Emission Source Type	GHG Emission
Scope 1 – Direct Emissions	
Stationary Combustion	
- Fuel Combustion	CO ₂ , CH ₄ , N ₂ O
- Incineration of other materials	CO ₂ , CH ₄ , N ₂ O
Mobile Combustion	CO ₂ , CH ₄ , N ₂ O
Processes	CO ₂ , CH ₄ , N ₂ O, HFCs, PFCs, SF ₆
Refrigeration/Cooling Agents	HFCs, PFCs
Water Treatment	N ₂ O
Scope 2 – Indirect Emissions	
Indirect Emissions (electricity, steam purchase)	CO ₂ , CH ₄ , N ₂ O
Scope 3 – Other Indirect Emissions	
Indirect Emissions – upstream product usage, transport	CO ₂ , CH ₄ , N ₂ O (typical)
Indirect Emissions – downstream product usage, transport, etc.	CO ₂ , CH ₄ , N ₂ O (typical)

Note: *This listing is not all inclusive.*

It is important to remember that, for developing GHG inventories, the operations under evaluation should include the core business operations of the entity. While the inventory will assess the emissions being generated within the inventory boundary, it does not represent the total life-cycle analysis carbon footprint of the organization for all upstream and downstream activities that comprise the entity's operations. A water utility's footprint will typically be far larger than a utility's inventory.

The basic inventory must include Scope 1 emissions for all owned or controlled assets, depending on the choice of organizational boundary approach. Scope 2 emissions are a large portion of most GHG water utility inventories, and most registries require the inclusion of Scope 2 emissions, although there is possibility that these will not be included in future cap-and-trade programs in the United States and thus could become optional for external reporting. Because Scope 2 emissions are based upon purchased energy, energy efficiency efforts are a mechanism for achieving GHG emission reductions.

Again, the extent of the upstream and downstream activities to include as Scope 3 emissions is left to the discretion of the entity. A good rule of thumb is to include those activities that are directly related to the core business activities of the entity. Out-sourced activities on which the entity may have some impact for reducing GHG emissions through incentives or other climate change objectives should be considered for inclusion. The objectives of the inventory should also be taken into account when determining the extent of Scope 3 emissions to be included. If an entity wants to determine the carbon footprint of its total life cycle, Scope 3 sources should be added to the extent that accurate data and accepted methodologies for the emissions quantification are available. The requirements of the reporting program or registry will also determine the type of Scope 3 emissions that can be included in the inventory.

Figure 4.1 provides a simple depiction of the concept of inventory versus footprint. An inventory consists of the elements included in the box, including facilities associated with source, treatment, conveyance (distribution), buildings, and fleet (described further in Section 6). Elements within the oval are associated with the overall footprint.

For example, consider General Water District, which owns two treatment plants with ozone and granular activated carbon (GAC), a distribution system with multiple pressure zones, a fleet of vehicles, administration buildings located apart from the treatment facilities, and a raw water reservoir and raw water pump station. General Water District does not own the pipelines and diversion structures associated with raw water intake. Solids are dewatered onsite, and disposed of by a third party. In terms of GHG inventory, General Water District has several elements that contribute to overall emissions, including the treatment plants, the distribution system, fleet vehicles, administration buildings, and raw water pump station and reservoir. However, because General Water District purchases liquid oxygen (LOX) from an outside chemical supplier, GAC is regenerated offsite, and a third party disposes of solids, General Water District does not have to account for these associated GHGs as part of an inventory. However, all these activities contribute to the overall utility footprint. Should General Water District switch to onsite LOX generation and onsite GAC regeneration, then these activities would have to be accounted for in the utility GHG baseline. Similarly for solids disposal, if General Water District owned the trucks in question, they would be included in the inventory.

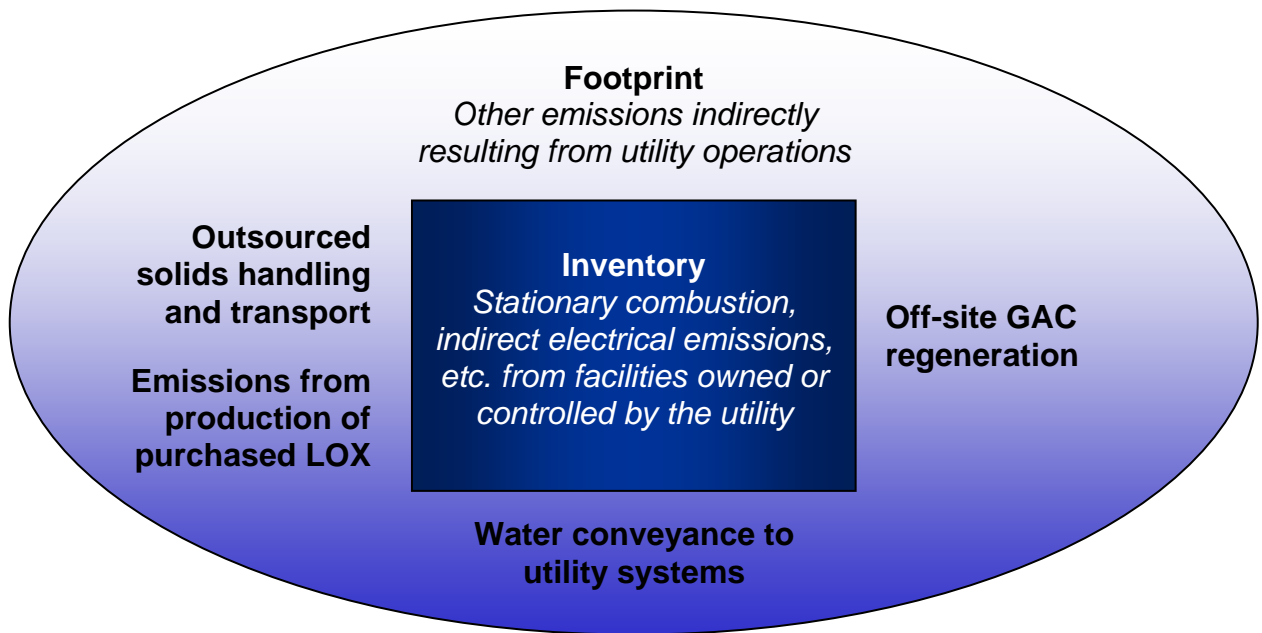


Figure 4.1 Example of inventory vs. footprint boundaries

Therefore, from an inventory perspective, a water utility is not responsible for calculating the GHG emissions associated with the purchase of chemicals or solids handling if these activities are not within its actual organizational boundary. However it may wish to track these emissions so that the true impact of future in-sourcing of these activities or other process changes may be determined or for accurate assessment of the overall impacts of its operations may be performed.

CHAPTER 5

DATA MANAGEMENT AND SYSTEMS

Data management is a key technical issue that contributes to a successful GHG inventory, both for baseline purposes and ongoing tracking. A water utility must examine the detail level achievable and necessary for GHG calculations and ensure consistency and quality assurance in data collection techniques. This section describes some of the elements of a successful data management system by which a water utility would establish a baseline and subsequently update inventories over time.

5.1 DECIDING ON THE LEVEL OF DATA TO COLLECT

Before an entity can begin quantifying GHG emissions for inclusion in the emissions inventory, it must decide on the level of activity data to collect. Considerations include the answers to these questions:

- How is data managed (by facility or entity-wide)?
- Is energy consumption data available for individual equipment items?
- Are purchases made in bulk?
- Are the facility meters appropriate or do submeters exist that are more representative?

The type of data detail level that can be collected by a water utility is termed “granularity.” Determining where the data are and how it is managed can guide the data granularity decision.

To the extent possible, an entity should obtain data at the lowest level, that is, the equipment or unit level. Having this level of data decreases the number of assumptions that must be made to complete emissions quantification and allows better understanding of opportunities for emission reductions and the impact of reduction efforts. The next preferred level of data would be grouped sources within the same source category. Grouped sources should be of like nature (for example, emergency generators, fuel oil boilers, natural gas heaters, gasoline trucks). Grouped source data is usually maintained at the facility level, but could also be maintained at the corporate level when the sources utilize minimal resources annually. Often, natural gas and electricity use for a facility is metered only for the entire facility, and equipment-level consumption data is not available.

If equipment/unit level or grouped data is not available, it is acceptable to use bulk or mass data (for example, total fuel purchased by fuel type, total electricity purchased, total miles traveled). Bulk data is usually maintained at the corporate level when purchasing functions are centralized. Bulk data may also be available at the facility level when purchases are made in bulk for the entire site, utility bills are submitted based on a facility meter rather than unit submeters, or operations data is maintained in a central data management system. Assumptions around equipment, vehicles, or process operations will have to be made when using bulk data.

Use of bulk data for items such as fuel will not significantly decrease inventory accuracy. However, use of more granular data may assist in identifying and tracking potential emission reduction projects. Ability of operations staff to see the impact of their conservation efforts serves as a motivator that can be lost if only facility-wide or entity-wide summary information is available.

5.2 COLLECTING AND MANAGING ACTIVITY DATA

Once you have determined the level at which data is managed and/or available, the activity data must be collected. Because a GHG inventory touches various parts of an entity's operations, multiple sources of data may be accessed for the appropriate activity data for the identified source categories. Source categories are described further in Chapter 6.

The use of databases, data warehouses, and Internet data management systems allows for activity data retrieval from a centralized location. If a data management system is in place, data can be obtained by querying the respective database (for example, purchasing, fleet, facilities) and/or searching the archives of operational systems for process-related data. Databases and data management reports should be archived for future reference.

If electronic data management systems are not used within an entity and its facilities or data are not centralized, it may be necessary to develop data collection sheets, forms, or electronic systems to capture the data. Data collection sheets can be formatted to obtain the necessary data for quantifying the emissions from a given source category. Data collection sheets can also be electronically submitted for data capture, data review, and archiving. The data collection sheet would also allow for entry of data that may be maintained in hard copy reports (for example, monthly operations reports, analytical analysis reports, annual energy reports).

A variety of commercial software tools are available from vendors to manage environmental data. Such software, when properly implemented, can frequently reduce the effort required for data collection and management, provide automated calculation and reporting capability, and provide “calendar” functions that send out reminders of regulatory reporting deadlines.

Selection of data management systems—whether paper data forms collected by an inventory manager, spreadsheet tools maintained by email or by storage on a server, custom software tools developed for a specific utility, or commercial tools adapted and implemented to fit particular needs—should be accomplished early in the inventory planning process. Selection factors include, but are not limited to, data volume, number of data sources, number of personnel involved, and existing use of data management tools for other purposes in the same organization.

5.2.1 Data Security

Most of the existing systems that maintain activity data for GHG inventory purposes already provide some data security features (for example, user identification and password, departmental database accessibility via the intranet). These systems are usually located on a central server on the entity's internal network and under the control of information technology security and back-up standards. Spreadsheet tools that are used for collecting data and calculating GHG emissions data are sometimes located on a central server or a personal computer. These tools should have access and/or write protection to ensure data cannot accidentally be modified by persons who have access to the server but do not own the data.

5.2.2 Data Collection Frequency

Activity data should be compiled at least annually. Many reporting registries require annual data submittal, with the reports typically being due in the first or second quarter of the following year. However, activity data may be collected on a daily or monthly basis by the

respective departments responsible for maintaining the information (for example, operations, purchasing, or fleet), and there are some advantages to more frequent data analysis. For example, for management of emissions within a future permit limit or allocation cap, or for monitoring of progress towards a voluntary reduction goal, analysis of monthly data may be beneficial to determine if any corrective action is required for the organization to achieve its goals.

5.3 QUALITY ASSURANCE

Regardless of the data management tools and collection frequency selected, it is important that data quality assurance procedures be designed and followed. Checks should be implemented to verify that activity data (such as fuel consumption, electricity purchases) that are entered into electronic tools accurately match the meter reading records, utility invoices, or other source records. Checks should also be required to ensure that all unit conversions, use of emission factors, calculation methodology, and summation of equipment- or facility-level data to entity totals are performed consistently and accurately.

5.4 DETERMINING A BASE YEAR

The base year inventory serves as the basis for comparison for subsequent year inventories and assessment of the effectiveness of reduction efforts and progress toward reduction goals. The effects of organizational and methodology adjustments to the GHG emissions inventory are reviewed against the base year. When choosing a base year, an entity should typically choose the first inventory year in which complete and accurate data is available for estimating emissions across all source categories.

In some cases, the reporting program and/or registry under which an entity is reporting dictates the base year. In these instances, the reporting program and/or registry guidelines should be followed. For example, TCR defines a base year as the first year of complete GHG reporting, and that base value shifts in response to organization changes that result in an increase in emissions of greater than five percent. The CCAR has similar policies, with the exception that the base year is updated when structural changes to the organization occur that create a change in emissions of greater than ten percent.

It should be noted that when determining a baseline inventory, hydrologic conditions will have an impact on the inventory magnitude. Utilities that have hydropower facilities or access to hydropower may experience a lower baseline in a water-rich year (i.e., reservoirs are higher, pumping costs are reduced, and emission intensity of grid power may also reduce if electric utilities can rely more heavily on hydropower) as compared to drier years. However, subsequent years with dissimilar hydrologic conditions will show variations from the baseline year inventory. Drier years could result in increased distribution system and source pumping, increasing an inventory total. While the impact of hydrologic conditions in the base year, and subsequent increases or decreases to GHG emissions relative to that base year, may be outside of the control of the utility, recognition of these impacts will be important to assessing progress towards GHG management goals.

5.5 PROCEDURES FOR UPDATING BASELINE INVENTORIES

GHG program design should specify the procedures to be used to determine when and how inventories for previous years should be updated. Triggers for such updates may include organizational changes, methodology changes, and/or correction of errors due to internal or external audit findings.

5.5.1 Acquisitions/Divestitures and Impact on Base Year Value

For most reporting protocols, the emission estimate from the previous year should be adjusted if facilities are acquired from or divested to other organizations. If an entity acquires a facility that existed during the base year and subsequent reporting years, the emissions from that facility's base year and subsequent years are added to the emissions inventories of the entity's base year and subsequent reporting years. If the facility did not exist in the base year or subsequent reporting years, no adjustment to the entity's base year or subsequent reporting years is necessary.

In the event that an entity transfers ownership or control of a facility that existed during the base year and subsequent reporting years, that facility's emissions are subtracted from the emissions inventories of the entity's base year and subsequent reporting years. If the facility did not exist in the base year, no adjustments to the entity's base year are made. The facility's emissions data from each corresponding reporting year would also be removed from the entity inventories.

In the event of in-sourcing and/or outsourcing core business activities, the emissions from facilities included in the organizational change should be treated as a transfer of ownership/control. If the in-sourced activities were previously included as Scope 3 emissions, no adjustment to the base year will be necessary. However, if the in-sourced activities were not previously included in the inventory, the base year should be adjusted if those activities occurred in the base year. For the outsourcing of activities, the converse is true. If activities previously completed by the entity and recorded under Scope 1 are outsourced, but included in Scope 3, no base year adjustment should be made. However, if the outsourced activities are not included as part of Scope 3, the base year should be adjusted to reflect the transfer of activities from the entity boundaries.

These adjustments to base year emissions for organizational changes are important for avoiding artificial increases or decreases to emissions when tracking reductions. For example, without such adjustments, an entity could reduce its emissions by selling or outsourcing activities, but clearly no true environmental benefit would occur if a different entity assumes the same GHG emissions.

In the event of organic growth (for example, increase in throughput or services, new facility brought online) or organic decline (for example, decrease in throughput or services, closing of facility), no adjustments will be made to the base year. The resulting increases or decreases in GHG emissions resulting from these activities are considered to be naturally occurring as part of business activities.

5.5.2 Methodology Changes

If better data becomes available for the base year compared to subsequent years, adjustments should be made to the base year to ensure consistency of historical reporting. In the event of a change in methodology or emission factors that result in a 5 percent or greater (or threshold set by the reporting program or registry the entity is reporting under) change in the overall emissions total or one source category, the base year should be adjusted. This procedure is consistent with TCR policy, but other program requirements may differ.

5.5.3 Correction of Errors

In the event that errors are found during internal and/or external audits of the GHG inventory, the inventory year(s) affected by the errors should be adjusted. If the error was found in the base year emissions quantification and repeated throughout subsequent year inventories, all years should be updated using the corrections. If errors were found in a single year, only that year should be corrected. Typical errors include using the wrong emission factor for a given activity data, inaccurate assumptions for a source category, incorrect unit conversions, and quantification errors in electronic tools. As with methodology changes, it may be advantageous to predefine numeric thresholds (for example, an error results in greater or less than 5 percent change) that would trigger a revision and re-reporting of the inventories of the previous year.

5.6 DOCUMENT RETENTION AND INVENTORY VERSION CONTROL

It is recommended that utilities develop a document retention policy. Frequently, this policy specifies retention of all documents (for example, utility bills, reports, analytical data, operations logs) used to generate the emissions inventory for at least 5 years. The retention policy should be consistent with the goal year for achieving emission reductions under the reporting program or registry and/or for the duration of an offset projects lifetime. The records should be maintained long enough to adjust the base year emissions inventory, if needed.

5.7 DEFINITION OF ROLES AND RESPONSIBILITIES

The identification of an inventory manager is key to consistently developing the inventory over time. In general, the inventory manager leads the development of the GHG emissions inventory. The inventory manager collects data from the respective entity departments and/or facilities responsible for the source category activity data; inputs the data into the inventory calculation tool, if applicable; oversees inventory quality assurance and quality control; and reports final emissions inventory data in an entity-wide consolidated format. The inventory manager also is responsible for the continuous improvement of the inventory development process.

Because a GHG inventory is compiled from several information sources, a listing of the entity staff consulted when preparing the emissions inventory should be developed. At a minimum, the document should identify each staff member, job title or function, and responsibilities within the GHG management program. As part of the continuous improvement process, the GHG inventory manager should review and update the list annually.

It is the GHG inventory team's collective responsibility to gather all necessary data for completing the emissions quantification and to ensure data quality and accuracy over time. Additional team members may be identified as the emissions inventory is continually improved and developed in subsequent years. Additional roles and responsibilities should be developed over time, if necessary.

As roles, responsibilities, and personnel change, inventory data needs should be communicated to the person filling the respective position that provides the requisite activity data. Inventory data needs and data collection procedures should be documented to ensure accuracy and consistency over time.

Management oversight responsibilities and procedures should also be defined. Successful GHG management programs include the support of top-level management of the organization.

5.8 EMPLOYEE TRAINING

A training plan should be developed to assist personnel who have responsibilities for the GHG program in understanding the purpose for their work and the procedures necessary to do it correctly. For example, inventory managers should have training or time to study the relevant quantification protocols identified in this guidance and as published by the reporting registry. Staff responsible for inventory calculation should understand the calculation principles and methodology, choice of emission factors, and other relevant concepts. Staff with data collection responsibilities should understand the use of the information, use of the data management tools, and any unit conversions that will need to be performed on the data before reporting. All staff involved should understand the overall management or reduction strategy so they can contribute to its success.

Training can be completed as an independent study activity, within job function training, as part of a workshop, or part of web-based training. GHG team roles and responsibilities should be completed as part of the overall job function. It is important for the team members to understand the way in which the data they are collecting will be used in the inventory development process. Team members should also be trained on procedures for collection of the most accurate activity data and quantification of emissions associated with that activity data.

As new team members are identified and/or existing team members are replaced, the inventory process should be reviewed with the new personnel prior to completing data gathering activities for development of the GHG emissions inventory.

5.9 INTERNAL AUDITS AND EXTERNAL VERIFICATION PROGRAMS

The decision to select internal or external verification of a GHG inventory is based on several factors that are described below.

5.9.1 Internal Audits

Depending on the size and structure of an entity, an internal audit team may or may not exist. The purpose of an internal audit is to identify gaps and errors prior to disclosing GHG inventory data to the reporting program or registry. The internal audit should be completed by personnel familiar with GHG accounting and reporting principles as well as the guidelines of the reporting program or registry, but not involved in the inventory development process. If an entity

decides against completing a formal internal audit, the inventory should be reviewed internally for consistency with established GHG accounting and reporting principles.

Any findings resulting from the internal audit or review should be tracked to completion as corrective actions. Corrective actions should be assigned to a responsible person, with a timeframe for completion, and a date for follow-up. In some instances, corrective actions may trigger an inventory base year or subsequent year inventory update.

5.9.2 External Audits or Verification

Most GHG inventories are completed using personnel within the entity organization. In some cases, third parties are involved with the development of the GHG inventory. In either instance, the entity may deem it necessary to have an external review, validation, or verification of the credibility of the GHG emissions inventory based upon how the inventory data will be used or presented (for example, reporting to a non-governmental organization, publicly communicating data via an internal or external website or publication, meeting a mandatory reduction goal). The external review or validation should be completed by parties not involved with the development of the inventory. TCR, for example, requires third-party verification of all emission reports. Initial indications are that USEPA will not require third-party verification under the mandatory reporting program that is in development, although organizations may still find it valuable to have independent confirmation prior to public reporting.

A key component to completing an external review and/or verification is identifying the protocol against which the external verification will be performed. Generally, the inventory verification aligns with the requirements of the reporting program or registry. If the entity is not involved in a reporting program or registry, the verification may align with the internationally accepted principles of the WRI/WBCSD GHG Protocol Corporate Standard, ISO guidelines, or the prominent local, state, or regional reporting program.

All findings resulting from the external audit or verification should be tracked to completion as corrective actions. Corrective actions should be assigned to a responsible person, with a timeframe for completion, and a date for follow-up. In some instances, corrective actions may trigger an inventory base year or subsequent year inventory update.

CHAPTER 6

WATER UTILITY ISSUES

The previous sections of this report have provided detail on general GHG inventory and accounting concepts and practices. This chapter provides guidelines on issues of particular significance to water utilities. These issues include recommended organization of emission inventories to align with typical water utility management structure, impact of generation of renewable power—in particular hydropower—by water utilities on emission inventories, and accounting issues regarding water conservation projects.

6.1 DATA ORGANIZATION

A GHG inventory baseline for water utilities is more meaningful if the data is analyzed in a way that is congruent with typical water utility functionality. To assist in data organization, it is recommended that emission data be organized around the six sectors within a utility that describe typical facility types and/or functional structures. While this organizational structure is not typically required by relevant protocols or registries, it provides the necessary information for most GHG registries and fulfills the information assembly requirement in a format that can more easily be used to benchmark. The six sectors include the following:

- **Source.** The source water sector accounts for GHG impacts associated with all activities associated with water intake and transport to the treatment facility. All intake structures, pump stations, and screening/solids handling facilities that consume power should be included in this sector.
- **Treatment.** The water treatment facility's power consumption includes that of all treatment processes and the buildings associated with the treatment plant. The total power usage of the water treatment facility would be the summation of usages and activities (including fugitive emissions) for all treatment facilities. The authors recommend that any distribution pumping conducted at the treatment plant be included in the distribution system calculations and not in the treatment plant calculations.
- **Distribution.** Every utility will have a unique distribution system that results in a variable use of energy. Some systems may have to pump water up thousands of feet to reach customers using multiple booster pump stations, while others can simply gravity feed the water and have little no additional pumping requirements. For many utilities, distribution is the largest energy sector.
- **Buildings/Infrastructure.** This sector collects information on all non-treatment buildings and infrastructure associated with the utility, including all operations and maintenance buildings, administrative buildings, and all other buildings controlled by the utility.
- **Fleet.** This sector includes the energy use associated with use of the vehicles within a utility, including all mobile combustion sources such as cars, trucks, and heavy equipment.
- **Other.** Where possible, all power usage and GHG emissions should be included in one of the five sectors listed above. However, there are times when it is not possible to categorize usage in this manner; as such, this sector can be used for those uses and

activities not considered part of the first five sectors. Examples might include large reservoirs or land areas that are being leased or otherwise used and have GHG impacts owned by the utility. In addition, a utility may decide to include additional GHG emissions that could be associated with the utility operations, such as private vehicles and commuting.

6.1.1 Impact of Organization on Water Utility Inventories

As noted above, the organization of an inventory can have a large impact on how a utility benchmarks its own performance. The six sectors permit a utility to understand its largest sources of GHG emissions and subsequently indicate to staff where reduction efforts should be focused. For example, distribution systems with multiple pressure zones, pumping systems, and pressure reducing systems can have a large impact on Scope 2, indirect electrical consumption. A utility with significant mobile source emissions may wish to examine the fuel efficiency of the fleet or changes to logistics to reduce miles traveled. By organizing GHG emissions data in a manner suggested below in Table 6.1, a water utility can develop a benchmark in both the horizontal direction (total GHG inventory) as well as the vertical direction (by Scope). For example, a value for all Scope 1 Mobile Combustion GHG equivalents can be generated, and similarly, the GHG inventory for the Source sector can be determined.

It is advised that the utility maintain data in both horizontal and vertical summations. Vertical summation will meet the reporting requirements of TCR and CCAR. Horizontal summation will allow more focused management and more meaningful benchmarking against other utilities. Issues regarding comparison to other water utilities are discussed in Chapter 11.

6.2 RENEWABLE ENERGY

A key concern raised by various stakeholders during the development of this document was in regard to the onsite generation of renewable energy, in particular, hydropower. While each situation may vary depending on requirements of the reporting program, status of the applicable state renewable portfolio standard, vintage of the project, and other factors, this section gives a brief overview of the issues.

Table 6.1
Recommended benchmarking by sector and scope

Sector	Scope 1 mobile combustion	Scope 1 stationary combustion	Scope 1 electricity generated	Scope 2 electricity purchased	Scope 3 other emissions	Total GHG inventory
Source						
Treatment						
Distribution						
Buildings						
Fleet						
Total						

This section provides broad guidance on four typical scenarios for generation of renewable energy by a water utility: 1) the water utility generates green power onsite and consumes it internally, 2) the water utility generates green power onsite and consumes it internally, but also sells Renewable Energy Credits (RECs) for the same power, 3) the water utility generates green power onsite, sells it to an electric utility or other entity, and uses grid power for other facilities, 4) the water utility generates green power onsite, sells it to an electric utility or other entity, sells RECs for the same power, and uses grid power for other facilities.

6.2.1 Case 1: Water Utility Generates Green Power and Consumes It Internally

This first case is relevant to facilities that generate hydropower or other renewable energy supply to satisfy internal electrical demands and is the most straightforward. In this scenario, the water utility would calculate zero GHG emissions for this portion of its power. Additional grid power purchased would be treated as a normal Scope 2 emission, and any excess power sold would be treated as with Case 3 or Case 4 below. In the case of onsite biomass-fired power production, program-specific guidance would need to be checked to determine if the CO₂ emissions are considered biogenic.

6.2.2 Case 2: Water Utility Generates Green Power, Consumes It Internally, and Sells Renewable Energy Credits

RECs are similar to carbon offsets in that the value to claim the “green” attributes of a particular action can be sold on the market. RECs are typically sold in units of megawatt-hours (MWh) of green power generation, and can be used in compliance markets by utilities needing to comply with an RPS but lacking sufficient internal or wholesale green power supply, or in the voluntary markets by entities wishing to claim the green attributes for other purposes.

Because the entities that certify and track RECs do not typically apply additionality tests to RECs unlike for carbon offsets, continued debate exists in the GHG management community as to whether a REC can be used as a carbon offset. Most existing protocols allow the use of purchased RECs to offset Scope 2 emissions only, with the “negative” emission calculated based on the grid emissions intensity of the location that the green power was generated (not where the REC was used).

Green-e, the program certifying the majority of the RECs in the United States, disqualifies energy from projects constructed prior to 1997. Thus, the majority of the existing hydropower projects do not qualify for creation of RECs.

One principle is fairly clear and consistent between protocols: if the REC is sold and the purchaser of the REC is claiming the green attributes (presumably including the carbon offset), then the seller of the REC cannot claim the same green benefit.

In this case, the water utility would still have zero Scope 1 emissions from the generation of the hydropower or other non-CO₂ emitting renewable power. However, depending on program requirements, the water utility will likely include Scope 2 emissions for the same power, assuming an emission intensity equal to the grid power in the area where the green power was generated.

6.2.3 Case 3: Water Utility Generates Green Power, Sells It to Electric Utility, and Utilizes Grid Power for Other Facilities

This third case would include water utilities that generate hydropower or other green power and sell it to the local electric utility or other entity, but does not sell RECs to a third party. This case becomes more complicated because of the variations in individual state RPS requirements and treatment of the power by the electric utility.

Individual state regulations may or may not allow the electric utility to claim older projects against RPS requirements. Furthermore, the electric utility may or may not be selling the power at a premium rate to consumers wishing to use “green” power.

In any case, the generation of the green power would result in zero Scope 1 emissions. If no claim to the green attributes of the power is made by another party, under some programs there may be the possibility of claiming it as an offset to Scope 2 emissions from other grid power purchase by the water utility, although program specific guidance should be consulted. Any such offset could not be claimed against Scope 1 emissions.

6.2.4 Case 4: Water Utility Generates Green Energy, Sells to Electric Utility, Sells RECs, and Utilizes Grid Power for Other Facilities

In this situation, again there would be no Scope 1 emissions. The water utility would certainly have no claim to “negative” emissions for the green power sold, because that claim was sold with the REC. The electric utility would claim the power against the RPS only if it was the purchaser of the REC; otherwise, the third-party REC purchaser would likely take the offset against its Scope 2 emissions or RPS obligations. The water utility would calculate Scope 2 emissions for purchased grid power using normal procedures.

6.3 WATER CONSERVATION PROJECTS

Impact of water conservation projects on utility GHG inventories was also a key concern during development of this document. This section discusses some of the principles involved.

Scope 1 or Scope 2 emissions of up to four entities could be affected by a water conservation project. The water utility would likely achieve reduced Scope 1 and Scope 2 emissions due to reduced water transport and treatment needs. Any upstream water supply entity may also see reduced emissions due to reduced pumping requirements. The water consumer, residential or commercial, may reduce its Scope 1 or Scope 2 emissions through reduced water heating and/or pumping. Finally, the electric utility or utilities serving these first three entities will likely achieve reduced Scope 1 emissions because grid electrical demands would decrease.

If specific contractual arrangements exist between the upstream water supplier and/or water consumer and the water utility, and if the reduction qualifies as an offset under the rules of the applicable reporting program, there is the possibility for the water utility to claim these offsets against its own Scope 1 or Scope 2 emissions. This claim for offsets would require independent registration of the offset with the applicable registry. Most likely, the reductions would be attributable only to the water utility’s Scope 3 emissions if it chooses to report those emissions. Similarly, but less likely, the reduction of Scope 1 emissions at the electric utility could be credited against the water utility’s Scope 1 emissions only if a specific contractual agreement exists and if the reduction otherwise qualifies as an offset by the program rules.

Note that impact of water conservation efforts on a water utility GHG emission inventory will vary significantly depending on whether emissions are reported on an absolute or an intensity basis. As discussed, reductions in water pumping and treatment will clearly reduce the total Scope 1 and Scope 2 emissions of the water utility, however if reported on a per gallon basis, the benefits of such projects may be masked. Conversely, if consumer demand requires a water utility to increase total water supply, absolute GHG emissions will likely increase, and could mask impacts of energy efficiency programs or other emission reduction efforts; in this situation, reporting of intensity-based emissions may better highlight improvements made by the utility.

CHAPTER 7

CALCULATING INDIRECT EMISSIONS FROM ELECTRICITY USE

All water utilities will have Scope 2 (indirect GHG emissions) from electricity use. The following information discusses calculation of GHG emissions from electricity use. As described in Chapter 6, it is suggested that data collection, calculations, and reporting be divided into the six utility sectors, that is, source, treatment, distribution, facilities, fleet, and other. These sectors are further used to define indirect emissions.

The guidelines of the CCAR were adopted for the procedures specified in Chapters 7, 8, and 9, although attempts were made to make the discussion applicable to other protocols as well. Subsequent to the initial development of this document, CCAR has changed its mission to focus on registry of GHG offset (reduction) projects. Initially established as a registry of entity-wide emission inventories for organizations with operations in California, CCAR staff were instrumental in the establishment of TCR, which has a similar mission but with a multi-state focus. The CCAR's role became somewhat redundant with that of TCR and, as such, has recently announced new primary goals of 1) recognition of early action by its members under future regulatory scenarios, 2) focusing on GHG reduction projects, and 3) remaining active in GHG policy issues. The CCAR has recently announced the development of The Climate Action Reserve, which will track development and transaction of voluntary GHG reductions. Despite the change in the CCAR's role, CCAR methodologies are still relevant and consistent with the methodology of the TCR and other protocols, and example emission estimation methodologies from CCAR documentation are included in this report.

7.1 CALCULATING INDIRECT ELECTRICAL EMISSIONS

To calculate the emissions from electricity use, a three-step process was derived from a review of existing protocols. The following is an overview of the process, with each step subsequently detailed:

1. Select the appropriate electricity emission factors that apply to the electricity source used.
2. Determine the annual electricity consumption in each of the six sectors and determine the total annual emissions for all GHGs.
3. Convert non-CO₂ emissions to CO₂-e, and sum the total.

The generation of electricity through the combustion of fossil fuels typically yields CO₂ and, to a smaller extent, N₂O and CH₄. Emissions of N₂O and CH₄ will usually be *de minimis*, but are required by most protocols to be quantified. Additionally, whether the total CO₂ and CO₂-e gases are reported in English or metric units depends on the requirements of the protocol. If the total is required in metric tons, convert the total calculated in step 4.

The process is described in the following sections. Included are examples of how the data might be collected and organized.

7.1.1 Step 1: Select Electricity Emission Factors That Apply to the Electricity Source Used

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed, and it is reported in pounds or kilograms per kilowatt-hour (lbs/kWh or kg/kWh) of use.

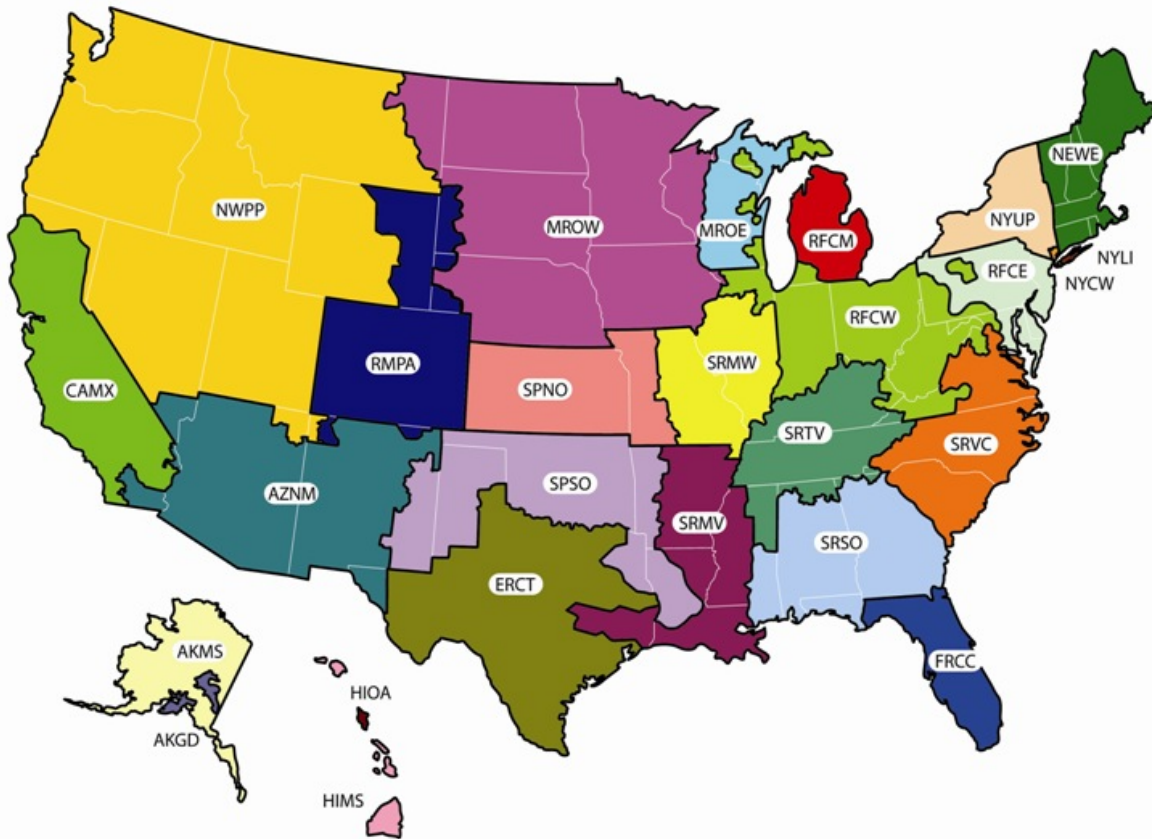
Consumers often find it difficult to determine the method of electrical generation for their power purchases, and there are significant differences in GHG emissions among the electrical generation techniques such as coal, gas, nuclear, solar, wind, and hydropower. Each has a significantly different impact on GHG emissions. Usually, consumers will be drawing grid power generated from a combination of these technologies. To alleviate this problem, regional power pool emission factors for electricity consumption have been developed to assist in determining emissions based on electricity consumed.

If certifiable emission factors can be obtained from the electric supplier, those factors could be used to calculate the indirect emissions from electricity generation, as they are more accurate than the default regional factors. Selection of emissions factors may depend on the protocols of the registry to which the emissions are reported. When encouraged by the registry or where non-grid power is consumed, certifiable emission factors from the electricity supplier should be used. When such factors are obtained, the user should clearly document the basis for the estimate and verify that the reported factors are in the range that would be expected based on knowledge of the generation method. Other protocols encourage use of average generation intensity for the power grid in which the consumer is located, as described below.

The CCAR, USEPA, and TCR encourage use of supplier-specific emission factors over grid-based factors. Emission factors should be selected based on an understanding of the requirements of the reporting program.

The energy source portfolio for individual electric utilities and regional grid supplies will vary from year to year. These variations are caused by a number of factors including, but not limited to, development of new power generation facilities; dispatch of new and existing facilities based on fuel prices, maintenance issues, and other factors; snowpack and hydrology issues for regions with significant hydro power generation; and carbon regulation. Therefore, electrical indirect GHG emission factors vary by year also.

Where supplier-specific emission factors are not available or where entities own facilities in different areas or that are supplied by different utilities, use of grid average emission factors may be appropriate. The USEPA's eGRID database provides regular updates to these grid average emission factors, and the database can be queried for individual utilities, state boundaries, and other boundaries. Most protocols recommend use of power grid subregion data, as depicted in Figure 7.1. Because the eGRID data is based on actual generation totals, time is required to compile and analyze the data. As such, there is typically a several-year lag in the availability of this information. For example, as of the 2009 publication date of this guidance, the most recent USEPA release of this data is eGRID2007, which contains 2005 generation data. The most recent data available should be used for emission inventories for a particular year. Program-specific guidance should be consulted regarding update of prior-year inventories as new information becomes available (e.g., if a 2009 inventory was developed using 2005 data, whether that inventory should be updated in 2012 or 2013 when 2009 actual data is available.)



Source: USEPA's eGRID 2007 subregion file (year 2005 data).

Figure 7.1 USEPA'S eGRID power pool regions

The eGRID database can be downloaded from <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html> (USEPA 2009). Some of the protocols publish the subregion data in guidance documents. The subregion data are not provided in this document because it would not be possible to capture the frequent updates to the information.

7.1.2 Step 2: Determine Annual Electricity Consumption in Each of the Six Sectors and Determine the Total GHG Emissions

Reporting indirect emissions from electricity consumption next requires determination of 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 electric bills contain the number of kilowatt-hours (kWh) consumed. A kWh is a measure of the energy used by electric loads, such as pumps, motors, lights, office equipment, air conditioning, and machinery. Alternatively, where water utility staff regularly read and record electric meter readings, or if meters are available for individual equipment items and such data granularity is preferred, this meter data can be used.

For water utilities, it is necessary to aggregate multiple electricity bills (energy readings) for each of the six sectors. The number of kilowatt-hours consumed should be collected monthly, recorded, and totaled at the end of the year by each of the six sectors that were previously

identified and described in Chapter 6. When the electric bill does not begin or end exactly on January 1 and December 31, but spans two calendar years, the power usage should be prorated according to the number of days billed in each year.

Table 7.1 demonstrates a simple spreadsheet for tracking of indirect electrical emissions from multiple facilities.

Collecting the electrical usage information is the most time-consuming and difficult part of the process of determining GHG emissions. The necessity of a coordinated effort and adequate planning cannot be over-emphasized.

7.1.3 Step 3: Convert Non-CO₂ Emissions to CO₂-e and Sum the Total

To incorporate non-CO₂ gases in the GHG emissions inventory, the mass estimates of these gases must be converted to CO₂ equivalents. To do this, the non-CO₂ GHG emissions in units of mass are multiplied by their GWP as shown in the equation below. Section 3.2 provides GWP values from the three most recent IPCC reports; the specific requirements of a reporting program must be determined to select the right values. Some registry tools such as CCAR's CARROT database perform this conversion automatically:

$$CO_2eq(lbs\ or\ kg) = GWP * nonCO_2GHG(lbs\ or\ kg)$$

Keeping track of non-CO₂ GHGs is not required by all registries. However, most registries will require this in the future if they do not do so currently. Establishing a baseline and tracking these gases is probably advisable.

Table 7.2 provides an example of how a water utility could record the conversion of non-CO₂ GHGs to CO₂ equivalents. An example of a completed table is shown in the example shown in section 7.2.4.

Table 7.1
Source electrical compilation form

Location	Annual electricity consumption (MWh)	EF for CO₂ (insert from step 1)	CO₂ lbs/year multiply EC by EF	EF for CH₄ (insert from step 1)	CH₄ lbs/yr multiply EC by EF	EF for N₂O (insert from step 1)	N₂O lbs/yr multiply EC by EF
Facility 1							
Facility 2							
<i>Increase number of rows to correspond with number of meter readings.*</i>							
TOTAL							

*For the Treatment and Distribution sectors, increase the number of rows to correspond with the number of unit processes and distribution processes, respectively.

Note: EF, emission factor; EC, electricity consumption

Table 7.2
Example non-CO₂ greenhouse gas conversion table

Area	CO₂ emissions (lbs)	CH₄ emissions (lbs)	CH₄ CO₂.e emissions (lbs)	N₂O emissions (lbs)	N₂O CO₂.e emissions (lbs)	Total CO₂.e emissions (lbs)
1 - Source Water						
2 - Treatment						
3 - Distribution						
4 - Buildings and infrastructure						
5 - Fleet						
6 - Other						

7.2 EXAMPLE: ESTIMATING ELECTRICITY USE AT WATER UTILITIES

The following hypothetical example illustrates the way that GHG emissions could be calculated for a utility that purchases all of its electricity and uses no green power. The three steps involved with calculating total GHG emissions for this Scope 2 source are included in the example below.

7.2.1 Step 1: Select the Electricity Emission Factors that Apply to the Electricity Used

The factors listed below and used in this example were obtained from USEPA's eGRID2007 database (USEPA 2009):

- Location: Denver, Colorado
- Region: RMPA (Western Electric Coordination Council [WECC] – Rockies Subregion)
- Data year: 2005
- CO₂ emissions rate: 1,883.08 lbs/MWh
- CH₄ emissions rate: 0.0229 lbs/MWh
- N₂O emissions rate: 0.0288 lbs/MWh

7.2.2 Step 2: Determine Annual Electricity Consumption in Each of the Six Sectors and Determine the Total GHG Emissions

Energy consumption and the associated emissions of CO₂, CH₄, and N₂O for each sector were compiled as shown in Tables 7.3 through 7.7.

In the treatment calculations, the meter for each building was read and the recorded data used for the calculation. The high-service pumps that are part of the distribution system are contained within the filtration/ozone building. The electricity consumption from the pumps must be subtracted from the filtration/ozone building total used to calculate treatment emissions and added to the distribution emissions. The method to determine the electric consumption is based

on the total horsepower (hp) and operation time of the high service pumps. This calculation is shown below:

$$\text{Consumption (MWh)} = 2 \text{ pumps} * 350 \text{ Hp} * 0.0007457 \text{ MW/Hp} * 24 \text{ hrs/day} * 365 \text{ days/year}$$

$$\text{Consumption} = 4572.64 \text{ MWh}$$

Note that, in the following examples, calculated results are shown to many more “significant figures” than are valid from an engineering accuracy perspective. This is done for clarity of the calculation example. In reality, results should be rounded based on the accuracy of the source data.

Table 7.3
Example annual electricity consumption for source water facilities

Location	Annual electricity consumption (MWh)	CO ₂ lbs	CH ₄ lbs	N ₂ O lbs
Intake structure #1 meter	13.0	24,480.04	0.2977	0.3744
Raw water pump station #1 meter	65.0	122,400.20	1.4885	1.8720
Screening/solids handling meter	32.5	61,200.10	0.7443	0.9360
Additional units				
TOTAL	110.5	208,080.34	2.5305	3.1824

Table 7.4
Example annual electricity consumption for treatment facilities

Location	Annual electricity consumption (MWh)	CO ₂ lbs	CH ₄ lbs	N ₂ O lbs
Pre-treatment building meter	35	65,907.82	0.8015	1.0080
Filtration/ozone building meter	4,747.64	8,940,185.93	108.7210	136.7320
<i>Subtract high service pump station</i>	<i>(4,572.64)</i>	<i>(8,610,646.93)</i>	<i>(104.7135)</i>	<i>(131.6920)</i>
Pre-chemical building meter	75	141,231.00	1.7175	2.1600
Post-chemical building meter	75	141,231.00	1.7175	2.1600
Additional buildings				
TOTAL	360	677,908.80	8.2440	10.3680

Table 7.5
Example annual electricity consumption for distribution facilities

Location	Annual electricity consumption (MWh)	CO₂ lbs	CH₄ lbs	N₂O lbs
High service pump #1*	2,286.32	4,305,323.47	53.3567	65.8460
High service pump #2*	2,286.32	4,305,323.47	53.3567	65.8460
Booster pump station #1 meter	2,286.32	4,305,323.47	53.3567	65.8460
Additional units				
TOTAL	6,858.96	12,915,970.40	157.0702	197.5380

*Values were calculated in treatment section above.

Table 7.6
Example annual electricity consumption for buildings and infrastructure

Location	Annual electricity consumption (MWh)	CO₂ lbs	CH₄ lbs	N₂O lbs
Operations and maintenance building meter	500	941,540.00	11.450	14.4000
Administrative building meter	750	1,412,310.00	17.1750	21.6000
Process control building meter	325	612,001.00	7.4425	9.3600
Utility main office	500	941,540.00	11.4500	14.4000
Remote services building	100	188,308.00	2.2900	2.8800
Additional buildings				
TOTAL	1,575	4,095,699.00	49.8075	62.6400

Table 7.7
Example annual electricity consumption for fleet vehicles*

Vehicle Type	No. of vehicles in fleet	Annual electricity consumption (MWh)	CO₂ lbs	CH₄ lbs	N₂O lbs
Electric golf cart	2	10	37,661.60	0.4580	0.5760
Additional vehicles					
TOTAL	2	10	37,661.60	0.4580	0.5760

*Note that this example, showing vehicle electrical consumption, assumes that a separate electrical meter and/or utility bill is associated with charging the batteries of these vehicles. If these vehicles are charged from electrical systems already included in building or facility estimates, such usage should not be double counted in this step.

7.2.3 Step 3: Convert Non-CO₂ Emissions to CO₂-e

To convert non-CO₂ emissions into CO₂-e, emissions, the gases must be multiplied by the proper GWP conversion factors as listed below. Results are added to CO₂ emissions to estimate total CO₂-e. GWP values from the SAR report (IPCC 1995) are used for this example. The converted data is provided in Table 7.8.

$$CH_4 \text{ lbs as } CO_2\text{-e} = CH_4 \text{ lbs} \times 21 \text{ (GWP)}$$

$$N_2O \text{ lbs as } CO_2\text{-e} = N_2O \text{ lbs} \times 310 \text{ (GWP)}$$

Table 7.8
Example data conversion of CH₄ and N₂O to CO₂-e

Area	CO ₂ emissions (lbs)	CH ₄ emissions (lbs)	CH ₄ CO ₂ -e emissions (lbs)	N ₂ O emissions (lbs)	N ₂ O CO ₂ -e emissions (lbs)	Total CO ₂ -e emissions (lbs)
1. Source water	208,080	2.53	53	3.18	987	209,120
2. Treatment	677,909	8.24	173	10.37	3,214	681,296
3. Distribution	12,915,970	157.07	3,298	197.54	61,237	12,980,506
4. Buildings and infrastructure	4,095,699	49.81	1,046	62.64	19,418	4,116,163
5. Fleet	37,662	0.46	10	0.58	179	37,850
6. Other						
Total	17,935,320	218.11	4,580	274.30	85,034	18,024,935

CHAPTER 8

CALCULATING DIRECT EMISSIONS FROM MOBILE COMBUSTION

This chapter applies to all utilities that operate motor vehicles or other forms of mobile sources and provides guidance on how to calculate direct emissions from mobile combustion (Scope 1). The following information should be available to calculate this type of emissions: the type of vehicles operated, vehicle year and state of registration and/or information on emission control type, and the 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.

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8.1 BACKGROUND

Mobile combustion sources are non-stationary emitters of GHGs and include all owned or leased vehicles defined as being within the organizational boundaries of the inventory as described in Chapter 4. If the organization contracts a company for chemical delivery, solid transport, etc., these emissions might be quantified as Scope 3, but would not be included in Scope 1 emission estimates. Similarly, emissions from employee commuting or business travel on commercial aircraft could be included in Scope 3 but would not be in the Scope 1 estimate.

CO₂ 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. Combustion emissions of CH₄ and N₂O, while also related to fuel consumption, depend 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 vehicle fuel consumption records are available, CO₂ emissions can be calculated. If there is only information on the vehicle miles traveled, the data will need to be converted to fuel consumption based on USEPA's mileage per gallon (mpg) estimates for the vehicles. Similarly, the same fuel economy data can be used to estimate miles traveled from fuel consumption data for CH₄ and N₂O emission calculation.

8.2 CALCULATING DIRECT CARBON DIOXIDE EMISSIONS FROM MOBILE COMBUSTION

To calculate the CO₂ emissions from mobile combustion, follow this two-step process:

1. Identify total annual fuel consumption by fuel type.
2. Calculate metric tons of CO₂.

The following example presents the two-step process for calculating direct emissions from mobile combustion. Included are examples of how the data might be collected and organized.

Step 1: Identify Total Annual Fuel Consumption by Fuel Type

Fuel Consumption Data

If a utility stores fuel at any of its facilities, the annual fuel consumption can be determined from bulk fuel purchase records. Use Equation 8.1 (as adopted from CCAR guidelines) to help determine 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.

$$\text{Total Annual Consumption} = \text{Total Annual Fuel Purchases} + \text{Amount Stored at Beginning of the Year} - \text{Amount Stored at End of Year} \quad (8.1)$$

Source: CCAR 2008, Equation III.7a, Total Annual Fuel Consumption from Bulk Fuel Records, page 39

In addition to 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.

Vehicle Mileage Data

If there is only annual mileage information for the vehicles owned and operated, it is possible to estimate fuel consumption by applying a default fuel economy factor using the following procedure:

1. Identify the vehicle make, model, fuel, and model years for all the vehicles owned and operated.
2. Identify the annual mileage by vehicle type.
3. Convert annual mileage to fuel consumption using the USEPA's fuel economy formula (Equation 8.2, as quoted by both CCAR and TCR).

$$\text{Total Fuel Use (gallons)} = \frac{\text{Total Mileage (miles)}}{(\text{Fuel Economy City (mpg)} \times 55\% + \text{Fuel Economy Highway (mpg)} \times 45\%)} \quad (8.2)$$

Source: CCAR 2008a, Equation III.7b, Fuel Use in Motor Vehicles from Mileage Records, page 39

The USEPA provides estimates of on-road fuel consumption for passenger cars and light trucks. Vehicle mileage may be converted to fuel consumption using the USEPA fuel economy estimates of the specific vehicle models in the fleet (USDOE EERE/USEPA 2009). This website provides two figures for the calculation: one for city driving and one for highway driving. CO₂ emissions are then calculated based on fuel consumption.

If there is more accurate information about the driving patterns of your fleet, consider applying a more specific mix of city and highway driving: otherwise use the USEPA estimate that 45 percent of a vehicle's mileage is highway driving and 55 percent is city driving (see Equation 8.2). If there are more than one type of vehicle involved, calculate the fuel use for each vehicle type separately.

For heavy-duty trucks for which no fuel efficiency information is available, CCAR guidance (CCAR 2008) suggests efficiency of 6 mpg for gasoline-powered trucks and 7 mpg for diesel-powered trucks.

Step 2: Calculate Metric Tons of CO₂

From program-specific guidance (for example, Appendix C, Table C.4 for CCAR), select the appropriate transport fuel and record the emission factor associated with the fuel. Using Equation 8.3, multiply the factor by the total fuel consumption and then by 0.001 to convert from kg to metric tons.

$$\begin{aligned} \text{Total Emissions (metric tons)} &= \text{Fuel Consumed (gallons)} \times \\ &\text{Emission Factor (kg CO}_2\text{/gallon)} \times 0.001 \text{ metric tons/kg} \end{aligned} \quad (8.3)$$

Source: CCAR 2008a, Equation III.7c, Total CO₂ Emissions from Mobile Combustion, page 39

8.3 CALCULATING CH₄ AND N₂O DIRECT EMISSIONS FROM MOBILE COMBUSTION

To calculate the CH₄ and N₂O direct emissions from mobile combustion, follow this seven-step process:

1. Identify the vehicle types, fuel, and model years of all vehicles owned and operated.
2. Identify the annual mileage by vehicle type.
3. Select the appropriate emission factor for each vehicle and fuel from program specific guidance (for example, Appendix C, Table C.5 for CCAR).
4. Calculate each vehicle type CH₄ and N₂O emissions and convert to metric tons.
5. Sum the emissions over each vehicle and fuel type.
6. Convert CH₄ and N₂O emissions to CO₂e.
7. Total CO₂e emissions from mobile combustion.

Step 1: Identify the Vehicle Types, Fuel, and Model Years of All Vehicles Owned and Operated

Emission factors for various fuel and pollution control technologies, as well as for default emission control technologies by vehicle type and model year, are provided in the guidance documents for most programs. The emission factors vary with model year because of changes to emission controls and catalysts.

Step 2: Identify the Annual Mileage by Vehicle Type

If mileage information is not available, but there is fuel consumption data by vehicle type model and year, it is possible to estimate the vehicle miles traveled using the USEPA fuel economy data of the specific vehicle models in the fleet. Use this value to calculate CH₄ and N₂O emissions based on vehicle miles traveled, as shown in Equation 8.4. If there is only information

on bulk fuel purchase, allocate consumption across vehicle types and model years in proportion to the fuel consumption based on the usage data available.

$$\text{Total Mileage (miles)} = \text{Fuel Use (gallons)} \times (\text{Fuel Economy City (mpg)} \times 55\% + \text{Fuel Economy Highway (mpg)} \times 45\%) \quad (8.4)$$

Source: CCAR 2008a, Equation III.7d, Vehicle Mileage from Fuel Use Records, page 40

Step 3: Select the Appropriate Emission Factor for Each Vehicle and Fuel from Program-Specific Guidance

Make sure that the emission factor corresponds to the model year of each vehicle.

Step 4: Calculate Each Vehicle Type CH₄ and N₂O Emissions and Convert to Metric Tons

Use Equation 8.5 to calculate both CH₄ and N₂O emissions for each vehicle type.

$$\text{Total Emissions (metric tons)} = \text{Emission Factor by Vehicle and Fuel Type (g/mi)} \times \text{Annual Mileage} \times 0.000001 \text{ metric tons/g} \quad (8.5)$$

Source: CCAR 2008a, Equation III.7e, Total CH₄ or N₂O Emissions from Mobile Combustion, page 40

Note that this calculation must be performed for each vehicle type for both CH₄ and N₂O. The final result will be metric tons of CH₄ and N₂O.

Step 5: Total the Emissions Over Each Vehicle and Fuel Type

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

Step 6: Convert CH₄ and N₂O Emissions to CO₂-e and Total

Using the IPCC GWP factors from Chapter 3, Table 3.1 and Equation 8.6, convert CH₄ and N₂O to CO₂ equivalents.

$$\text{Total CO}_2\text{-e (metric tons)} = \text{Total Emissions (metric tons)} \times \text{GWP factor} \quad (8.6)$$

Source: CCAR 2008a, Equation III.6c, Convert Non-CO₂ GHGs to Carbon Dioxide Equivalent and Sum Total, page 44

Step 7: Total CO₂-e Emissions from Mobile Combustion

Once Steps 1 through 6 have been completed, determine total CO₂-e emissions from mobile combustion by totaling all subtotals.

8.4 EXAMPLE: CALCULATING DIRECT EMISSIONS FROM MOBILE COMBUSTION

General Water District has 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. It purchases its fuel in bulk. Last year, the company purchased 235,000 gallons of motor gasoline and 5,000 gallons of CA diesel fuel. It 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 began the year with 500 gallons of CA diesel fuel in stock and ended with 1,000 gallons of CA diesel fuel in stock.

Note that, in the following examples, calculated results are shown to more “significant figures” than may be valid from an engineering accuracy perspective. This is done for clarity of the calculation example. In reality, results should be rounded based on the accuracy of the source data.

8.4.1 Calculating Carbon Dioxide Direct Mobile Emissions

To calculate the direct emissions from mobile combustion, follow this two-step process:

1. Identify total annual fuel consumption by fuel type.
2. Calculate metric tons of CO₂

Step 1: Identify Total Annual Fuel Consumption by Fuel Type

Using Equation 8.1, calculate the total annual fuel consumption by fuel type.

$$\begin{aligned} \text{Total Gasoline Consumption} &= 235,000 \text{ gallons} + \\ &20,000 \text{ gallons} - 10,000 \text{ gallons} = 245,000 \text{ gallons} \end{aligned}$$

$$\begin{aligned} \text{Total Diesel Consumption} &= 5,000 \text{ gallons} + \\ &500 \text{ gallons} - 1,000 \text{ gallons} = 4,500 \text{ gallons} \end{aligned}$$

Step 2: Calculate Metric Tons of CO₂

Per CCAR Appendix C, Table C.4, the CO₂ emission factor for motor gasoline is 8.81 kilograms (kg) per gallon; for diesel fuel, it is 10.15 kg per gallon. The conversion from kg to metric tons is 0.001 metric ton/kg. Using Equation 8.3, calculate the metric tons of CO₂ produced.

$$\begin{aligned} \text{CO}_2 \text{ from Motor Gasoline} &= 245,000 \text{ gallons} \times \\ &8.81 \text{ kg/gallon} \times 0.001 \text{ metric tons/kg} = 2,158.45 \text{ metric tons CO}_2 \end{aligned}$$

$$\begin{aligned} \text{CO}_2 \text{ from Diesel Fuel} &= 4,500 \text{ gallons} \times \\ &10.15 \text{ kg/gallon} \times 0.001 \text{ metric tons/kg} = 45.68 \text{ metric tons CO}_2 \end{aligned}$$

$$\text{Total} = 2,204.13 \text{ metric tons CO}_2$$

Source: CCAR 2008a, Equation III.7c, Carbon Dioxide Emissions Contribution of Each Fuel, page 42

8.4.2 Calculating CH₄ and N₂O Direct Mobile Combustion Emissions

To calculate the direct emissions of CH₄ and N₂O, follow this seven-step process:

1. Identify the vehicle types, fuel, and model years of all vehicles owned and operated.
2. Identify the annual mileage by vehicle type.
3. Select the appropriate emission factor for each vehicle type, fuel, and model year.
4. Calculate the CH₄ and N₂O emissions for each vehicle type and convert to metric tons.
5. Total the emissions by vehicle type, fuel, and model year.
6. Convert CH₄ and N₂O emissions to CO₂-e.
7. Total CO₂-e emissions from mobile combustion.

Step 1: Identify the Vehicle Types, Fuel, and Model Years of all the Vehicles Owned and Operated

Table 8.1 lists the vehicles types, fuel, and model year of the vehicles in General Water District's fleet.

Step 2: Identify the Annual Mileage by Vehicle Type

General Water District needs to allocate gross fuel consumption (that is, gallons consumed per year) by vehicle type and model year. For this example, General Water District calculates total fuel consumption based on fuel purchase receipts to obtain total gallons of fuel consumed for each vehicle type. General Water District then determines vehicle miles traveled using USEPA mpg estimates. Table 8.2 lists the vehicle type, fuel, model year, and total fuel consumption of the vehicles in the organization's fleet. Using Equation 8.4, General Water District calculates the total annual mileage by vehicle type. This analysis assumed that, based on the referenced fuel economy website (USDOE EERE/USEPA 2009), or alternative fuel economy data, average city/highway fuel economy for the passenger cars, light duty trucks, and heavy duty trucks was determined to be 20/25, 15/20, and 8/10 mpg, respectively.

Table 8.1
Example 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

Source: CCAR 2008a, page 42

Table 8.2
Example 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	CA diesel	1998	4,500 gallons

Source: CCAR 2008a, page 43

$$\begin{aligned} \text{Total Mileage – Passenger (mi.)} &= 225,000 \text{ gallons} \\ &x (20 \text{ mpg} x 55\% + 25 \text{ mpg} x 45\%) = 5,006,250 \text{ miles} \end{aligned}$$

$$\begin{aligned} \text{Total Mileage – Light Duty (mi.)} &= 20,000 \text{ gallons} \\ &x (15 \text{ mpg} x 55\% + 20 \text{ mpg} x 45\%) = 345,000 \text{ miles} \end{aligned}$$

$$\begin{aligned} \text{Total Mileage – Heavy Duty (mi.)} &= 4,500 \text{ gallons} \\ &x (8 \text{ mpg} x 55\% + 10 \text{ mpg} x 45\%) = 40,050 \text{ miles} \end{aligned}$$

Source: CCAR 2008a, Equation III.7b, Annual Vehicle Miles Traveled

Step 3: Select the Appropriate Emission Factor for Each Vehicle Type, Fuel, and Model Year

Table 8.3 lists the corresponding CH₄ and N₂O emissions by vehicle type, fuel, and model year (in this example, data from CCAR’s General Reporting Protocol, Appendix C, Table C.5 were used).

Step 4: Calculate the CH₄ and N₂O Emissions for Each Vehicle Type and Convert to Metric Tons

General Water District uses Equation 8.5 to calculate the CH₄ and N₂O emissions for each vehicle type, then converts the results to metric tons.

$$\begin{aligned} \text{CH}_4 \text{ Emissions (metric tons)} &= 0.04 \text{ g/mi} x 5,006,250 \text{ (mi)} \\ &x 0.000001 \text{ metric tons/g} = .2003 \text{ metric tons CH}_4 \end{aligned}$$

$$\begin{aligned} \text{N}_2\text{O Emissions (metric tons)} &= 0.04 \text{ g/mi} x 5,006,250 \text{ (mi)} \\ &x 0.000001 \text{ metric tons/g} = .2003 \text{ metric tons N}_2\text{O} \end{aligned}$$

Source: CCAR 2008a, Equation III.7e, Passenger Cars: Total CH₄ and N₂O Emissions, page 43

$$\begin{aligned} \text{CH}_4 \text{ Emissions (metric tons)} &= 0.05 \text{ g/mi} x 345,000 \text{ (mi)} \\ &x 0.000001 \text{ metric tons/g} = .0173 \text{ metric tons CH}_4 \end{aligned}$$

$$\begin{aligned} \text{N}_2\text{O Emissions (metric tons)} &= 0.06 \text{ g/mi} x 345,000 \text{ (mi)} \\ &x 0.000001 \text{ metric tons/g} = .0207 \text{ metric tons N}_2\text{O} \end{aligned}$$

Source: CCAR 2008a, Equation III.7e, Light-Duty Trucks: Total CH₄ and N₂O Emissions, page 43

Table 8.3
Example emission factors for each fuel and vehicle type

Vehicle type	Fuel	Model year	Methane (CH ₄) (g/mi)	Nitrous oxide (N ₂ O) (g/mi)
Passenger cars	Motor gasoline	2000	0.04	0.04
Light duty trucks	Motor gasoline	2000	0.05	0.06
Heavy duty trucks	Diesel	1998	0.06	0.05

Source: CCAR 2008a, page 43

$$\begin{aligned} \text{CH}_4 \text{ Emissions (metric tons)} &= 0.06 \text{ g/mi} \times 40,050 \text{ (mi)} \\ &\times 0.000001 \text{ metric tons/g} = .0024 \text{ metric tons CH}_4 \end{aligned}$$

$$\begin{aligned} \text{N}_2\text{O Emissions (metric tons)} &= 0.05 \text{ g/mi} \times 40,050 \text{ (mi)} \\ &\times 0.000001 \text{ metric tons/g} = .0020 \text{ metric tons N}_2\text{O} \end{aligned}$$

Source: CCAR 2008a, Equation III.7e, Heavy-Duty Trucks: Total CH₄ and N₂O Emissions, page 44

Step 5: Total the Emissions by Vehicle Type, Fuel, and Model Year

The previous steps allowed General Water District to identify the total metric tons of CH₄ and N₂O by vehicle type, fuel, and model year. The grand total of the metric tons provides General Water District with its total emissions from mobile combustion for the last year, as shown in Table 8.4.

Step 6: Convert CH₄ and N₂O Emissions to CO₂-e

General Water District uses Equation 8.6 to convert the total emissions of CH₄ and N₂O to a CO₂-e. For this example, use of GWP values from the SAR report are assumed.

$$\begin{aligned} \text{Total CO}_2\text{-e (metric tons)} &= .02199 \text{ metric tons CH}_4 \\ &\times 21 \text{ (GWP)} = 4.62 \text{ metric tons CO}_2\text{-e} \end{aligned}$$

$$\begin{aligned} \text{Total CO}_2\text{-e (metric tons)} &= .223 \text{ metric tons N}_2\text{O} \\ &\times 310 \text{ (GWP)} = 69.12 \text{ metric tons CO}_2\text{-e} \end{aligned}$$

Source: CCAR 2008a, Equation III.6c, Convert to Carbon Dioxide Equivalent, page 44

Step 7: Total CO₂-e Emissions from Mobile Combustion

The grand total of CO₂-e emissions for mobile combustion (shown in Table 8.5) comprises the metric tons of CO₂, CH₄, and N₂O converted to CO₂-e emissions.

Table 8.4
Example total emissions from mobile combustion

Vehicle type	Fuel	Model year	CH ₄ (metric tons)	N ₂ O (metric tons)
Passenger cars	Motor gasoline	2000	0.2003	0.2003
Light duty trucks	Motor gasoline	2000	0.0173	0.0207
Heavy duty trucks	Diesel	1998	<u>0.0024</u>	<u>0.0020</u>
Total			0.2199	0.2230

Source: CCAR 2008a, page 44

Table 8.5

Example total CO₂-e emissions from mobile combustion	
GHG	Metric tons CO₂-e
CO ₂	2,204.13
CH ₄	4.62
N ₂ O	69.12
Total	2,277.87

Source: CCAR 2008a, page 44

8.5 ALTERNATE FUEL TYPES

Some water utilities may use biofuel sources as an alternative or supplement to typical gasoline or diesel fuels for fleet vehicles. Most protocols will require the accounting of these types of fuels, which might include ethanol, biodiesel, and various blends of biofuels and fossil fuels. Separate reporting is usually required due to the split in fossil fuel/biogenic fuel components, which will result in a CO₂ emissions equivalent different (lower) than fossil fuel use alone. For example, according to TCR, separate reporting of biofuel is required. However, the biogenic portion of biofuel could be considered as "carbon neutral" and therefore while accounting may be necessary, biofuel does not add to a utility's inventory.

Another possibility is the use of natural gas, or other alternative fuel. Emissions from alternative fuel vehicles are calculated in the same manner as other gasoline or diesel mobile sources, with the exception of electric vehicles (TCR 2008). For instance, if the utility operates a compressed natural gas vehicle, the total amount of fuel consumed should be determined and the appropriate emission factor applied to calculate emissions. Protocols such as the TCR GRP (TCR 2008a), Tables 13.1 and 13.5, provide emission factors for alternative fuels.

Electric vehicles receive power from the connected electricity grid. Therefore, using electric vehicles produces indirect emissions from purchased electricity. To calculate these emissions, you must determine the quantity of electricity consumed and apply an appropriate emission factor (see Chapter 7) associated with the grid used by the water utility (TCR 2008).

As noted, at the current time the biogenic portion of biofuel is generally considered to result in a "net zero" carbon emission for the fuel consumer. However significant research continues on the life-cycle carbon impact of production and use of biofuels. In particular, the overall GHG benefits of corn-based ethanol have been questioned. It is unknown at this time whether future accounting would apportion the GHG emissions from biofuel production to the producer, consumer, or a combination of both. Readers are cautioned to stay abreast of current research on this topic and not to assume that all biofuels will always be considered carbon neutral for the consumer.

CHAPTER 9

CALCULATING DIRECT EMISSIONS FROM STATIONARY COMBUSTION

This chapter applies to all onsite use of fossil fuel in boilers or engines, and provides guidance on the calculation of direct emissions from stationary combustion. Emissions due to stationary combustion come from power generation, manufacturing, and other industrial activities involving the combustion of fossil fuels. Typical sources are manufacturing facilities, commercial furnaces, and generators for power production. The following information should be available to complete this calculation: the type of fuel consumed by the entity and the amount of fuel that was combusted in the reporting year.

In situations where biofuels or biomass are consumed, such emissions may be considered biogenic (that is, part of the closed loop carbon cycle and thus a net zero emission). Individual program guidance should be consulted to obtain emission factors and to determine whether these emissions should be included in the Scope 1 emission inventory. As noted in Chapter 8, questions remain regarding proper GHG accounting for biofuels (in particular, corn-based ethanol), and readers are cautioned to stay abreast of current research on this topic. In general, use of biomass such as wood in stationary combustion will likely continue to be considered a net zero carbon emission for the user, but more significant issues may exist regarding the life-cycle impacts of biofuels.

If an entity uses a Continuous Emissions Monitoring System (CEMS), stationary combustion emissions may be reported directly from CEMS reports.

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9.1 EMISSION FACTORS FOR STATIONARY COMBUSTION

In general, default emission factors for GHG emissions from the types of fuels commonly combusted by water utilities are well characterized in GHG registry documentation. For complex sources such as petroleum refineries and chemical plants, additional research may be required. However for water utilities, where natural gas or commercial liquid fuels are the predominant fuel type, detailed research will likely not be required.

Information on fuel heat and carbon content may be available from the fuel supplier. For example, some fuel suppliers invoice based on quantity of Btus or therms provided in natural gas. If so, use of such supplier-specific data is encouraged. If not, many protocols provide high-quality default data for GHG emissions per quantity of fuel based both on heat content (e.g., kg CO₂ per MMBtu of fuel) or mass or volume (e.g., kg CO₂ per ton of coal or kg CO₂ per standard cubic feet of natural gas). For example, the TCR GRP (TCR 2008) provides this information in Table 12.1. Additional information sources exist; for example, the CCAR GRP (CCAR 2008a) lists several sources of additional information on page 42, but again it is considered unlikely that water utilities will need such research to produce high-quality inventories.

When using fuel consumption records that are based on heat content, readers are cautioned to confirm that such records and emission factors are consistent with the use of higher heating value (HHV) or lower heating value (LHV). U.S. and international conventions are different in this regard, and significant errors can result from mismatch of heat value basis.

9.2 CALCULATING DIRECT EMISSIONS FROM STATIONARY COMBUSTION

Use this six-step process to calculate the emissions from stationary combustion:

1. Identify all types of fuel directly combusted as part of operations.
2. Determine the annual consumption of each type of fuel.
3. Select the appropriate adjusted emission factor for each fuel.
4. Calculate the CO₂ emissions for each fuel and convert to metric tons.
5. Calculate the CH₄ and N₂O emissions for each fuel and convert to metric tons.
6. Convert CH₄ and N₂O emissions to CO₂-e and sum all subtotals.

9.2.1 Step 1: Identify all Types of Fuel Directly Combusted as Part of Operations

Fuel types can include, but are not limited to, coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

9.2.2 Step 2: Determine the Annual Consumption of Each Type of Fuel

Annual fuel consumption can be determined by direct measurement, fuel purchase records, or sales invoices measuring any stock change using the following equation (measured in million British Thermal Units (Btus), gallons, or therms).

$$\begin{aligned} \text{Annual Consumption (MMBtu or gallons)} = \\ \text{Total Annual Fuel Purchases} - \text{Total Annual Fuel Sales} + \\ \text{Amount Stored at Beginning of Year} - \text{Amount Stored at Year End} \end{aligned} \quad (9.1)$$

Source: CCAR (2008a), Equation III.8a, Annual Consumption of Fuels, page 47

If fuel consumption data are not available in million Btus (MMBtu), gallons, or therms, the data can be converted using the conversion factors provided in Table 9.1 as quoted in the CCAR General Reporting Protocol (CCAR 2008a).

Table 9.1
Conversion factors

Unit	Multiplied by	Final Unit
Barrels	42.0	Gallons
Therms of natural gas	0.1	Million Btus
Thousand cubic feet of natural gas	1.03	Million Btus
Metric tons of coal, electric utility	22.488	Million Btus
Metric tons of coal, industrial coke	30.232	Million Btus
Metric tons of coal, other industry	24.790	Million Btus
Metric tons of coal, residential and commercial	26.323	Million Btus

Source: CCAR (2008a), page 47

9.2.3 Step 3: Select the Appropriate Adjusted Emission Factor for Each Fuel

Emission factors are provided in program guidance documents. Each fuel type has a specific emission factor that relates the amount of CO₂, CH₄, or N₂O emitted per unit of fuel consumed (either in kgs per MMBtu of fuel or kgs per gallon of fuel). CO₂ emission factors depend almost completely on the carbon content of the fuel. CH₄ and N₂O emission factors also depend on the type of combustion device and the combustion conditions.

Carbon Dioxide

Program guidance documents such as Appendix C, Table C.6 of the CCAR GRP (CCAR 2008a) provide CO₂ emission factors for the most common fuel types in kilograms of CO₂ per MMBtu, kilograms of CO₂ per gallon for liquid fuels, and kilograms of CO₂ per standard cubic foot of natural gas.

Some protocols incorporate a fraction combusted in the emission factor references because fuels are not typically completely combusted and thus not converted completely to CO₂. However, in recent updates, most U.S.-based guidance is incorporating a 100 percent oxidation factor for simplicity.

Methane and Nitrous Oxide

CCAR Appendix C, Table C.7 (CCAR 2008a) presents CH₄ and N₂O emission factors by activity sector and fuel type. In this context, “sector” refers to combustion unit size – industrial, commercial/institutional, or residential. For petroleum products, emission factors for CH₄ and N₂O are provided in kilograms per gallon consumed.

9.2.4 Step 4: Calculate the CO₂ Emissions for Each Fuel and Convert to Metric Tons

If fuel consumption is expressed in MMBtu, Equation 9.2 should be used. If fuel is expressed in gallons, Equation 9.3 should be used.

$$\begin{aligned} \text{Total Emissions (metric tons)} &= \text{Emission Factor (kg CO}_2\text{/Btu)} \\ &\times \text{Fuel Consumed (MMBtu)} \times 0.001 \text{ metric tons/kg} \end{aligned} \quad (9.2)$$

Source: CCAR 2008a, Equation III.8b, Total CO₂ Emissions (Fuel Consumption is in MMBtu), page 48

$$\begin{aligned} \text{Total Emissions (metric tons)} &= \text{Emission Factor (kg CO}_2\text{/gallon)} \\ &\times \text{Fuel Consumed (gallon)} \times 0.001 \text{ metric tons/kg} \end{aligned} \quad (9.3)$$

Source: CCAR 2008a, Equation III.8c, Total CO₂ Emissions (Fuel Consumption is in Gallons), page 48

9.2.5 Step 5: Calculate the CH₄ and N₂O Emissions for Each Fuel and Convert to Metric Tons

If fuel consumption is expressed in MMBtu, Equation 9.4 should be used. If it is expressed in gallons, Equation 9.5 should be used. Note: non-CO₂ gases may be *de minimis*.

$$\text{Total Emissions (metric tons)} = \text{Emission Factor (kg CH}_4 \text{ or N}_2\text{O/MMBtu)} \times \text{Fuel Consumed (MMBtu)} \times 0.001 \text{ metric tons/kg} \quad (9.4)$$

Source: CCAR 2008a, Equation III.8d, Total CH₄ or N₂O Emissions (Fuel Consumption is in MMBtu), page 48

$$\text{Total Emissions (metric tons)} = \text{Emission Factor (kg CH}_4 \text{ or N}_2\text{O/gallon)} \times \text{Fuel Consumed (gallon)} \times 0.001 \text{ metric tons/kg} \quad (9.5)$$

Source: CCAR 2008a, Equation III.8d, Total CO₂ Emissions (Fuel Consumption is in Gallons), page 48

9.2.6 Step 6: Convert CH₄ and N₂O Emissions to CO₂-e and Sum All Subtotals

Use the IPCC GWP factors from Table 3.1 to convert CH₄ and N₂O to the CO₂ equivalent.

9.3 ALLOCATING EMISSIONS FROM COGENERATION

In situations where electricity or steam from cogeneration systems is bought or sold, additional procedures are used to allocate the GHG emissions between the electricity and steam. For example, if Facility A operated a cogeneration system, consumed all steam internally, and sold electricity to Facility B, then Facility A would include all emissions from the cogeneration system in its Scope 1 inventory, but Facility B would include only a pro-rated portion of the cogeneration system emissions in its Scope 2 inventory.

Because few water utilities operate cogeneration systems or purchase steam or electricity from cogeneration systems, this guidance manual does not include detailed procedures for allocation of emissions. However, the reader should be aware that most protocols and registry guidance provides procedures for allocation of emissions for this situation.

9.4 EXAMPLE: CALCULATING DIRECT EMISSIONS FROM STATIONARY COMBUSTION

General Water District consumes natural gas for space heating and diesel in emergency generators in its California operations.

9.4.1 Step 1: Identify All Types of Fuel Directly Combusted as Part of Operations

To calculate direct emissions from stationary combustion, all relevant sector and location data must be obtained for each type of fuel as shown in Table 9.2.

Table 9.2
Fuel type, sector, and location

Fuel	Sector	Location
Natural gas	Industrial	CA
Diesel	Commercial	CA

Source: CCAR 2008a, page 50

9.4.2 Step 2: Determine the Annual Consumption of Each Type of Fuel

General Water District receives invoices for natural gas usage based on heating value (MMBtus) of fuel used in its facilities and purchases its diesel fuel in bulk by the barrel. Last year, it consumed 788,400 MMBtus of natural gas. It also purchased 250 barrels of diesel fuel. It began the year with 12 barrels in storage and ended the year with 24 barrels in storage. Using Equation 9.1, General Water District determined its diesel fuel consumption. The result, 238 barrels, can be converted to gallons by multiplying by 42 (see Table 9.1 for conversion factors).

$$\begin{aligned} \text{Annual Consumption of Distillate Fuel} &= 250 \text{ barrels} \\ &+ 12 \text{ barrels} - 24 \text{ barrels} = 238 \text{ barrels consumed} \end{aligned}$$

$$238 \text{ barrels consumed} \times 42 \text{ gallons/barrel} = 9,996 \text{ gallons}$$

Source: CCAR 2008a, Equation III.8a, Annual Consumption of Fuels, page 50

9.4.3 Step 3: Select the Appropriate Adjusted Emission Factor for Each Fuel

General Water District used the adjusted emission factors shown in Table 9.3 for each fuel used.

9.4.4 Step 4: Calculate CO₂ Emissions of Each Fuel and Convert to Metric Tons

General Water District used Equation 9.2 for fuel consumption expressed in MMBtu, and Equation 9.3 for fuel consumption expressed in gallons. Fuel consumption was then converted to metric tons.

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 53.06 \text{ kg CO}_2/\text{MMBtu} \\ &\times 788,400 \text{ MMBtu (natural gas)} \times 0.001 \text{ metric tons/kg} = 41,832.5 \text{ metric tons CO}_2 \end{aligned}$$

Source: CCAR 2008a, Equation III.8b, Carbon Dioxide Emissions from Natural Gas (MMBtu), page 51

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 10.15 \text{ kg CO}_2/\text{gallon} \\ &\times 9,996 \text{ gallons (distillate fuel)} \times 0.001 \text{ metric tons/kg} = 101.5 \text{ metric tons CO}_2 \end{aligned}$$

Source: CCAR 2008a, Equation III.8c, Carbon Dioxide Emissions from Distillate Fuel (gallons), page 51

$$\text{Total CO}_2 \text{ from All Sources} = 41,934 \text{ metric tons CO}_2$$

Table 9.3
Emission factors by fuel type, sector, and location

Fuel	Sector	Location	kg CO ₂ per		kg CH ₄ per		kg N ₂ O per	
			MMBtu	Gal	MMBtu	Gal	MMBtu	Gal
Natural gas	Industrial	CA	53.06	-	0.0059	-	0.0001	-
Distillate fuel/diesel	Commercial	CA	-	10.15	-	0.0014	-	0.0001

Source: CCAR 2008a, page 99

9.4.5 Step 5: Calculate CH₄ and N₂O Emissions for Each Fuel and Convert to Metric Tons

General Water District used Equation 9.4 for fuel consumption expressed in MMBtu, and Equation 9.5 for fuel consumption expressed in gallons. Note, both CH₄ and N₂O emissions from stationary combustion are likely to be *de minimis*.

Methane

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 0.0059 \text{ kg CH}_4/\text{MMBtu} \\ &x 788,400 \text{ MMBtu (natural gas)} x 0.001 \text{ metric tons/kg} = 4.652 \text{ metric tons CH}_4 \end{aligned}$$

Source: CCAR 2008a, Equation III.8d, Methane Emissions from Natural Gas (MMBtu), page 51

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 0.0014 \text{ kg CH}_4/\text{gallon} \\ &x 9,996 \text{ gallons (distillate fuel)} x 0.001 \text{ metric tons/kg} = 0.014 \text{ metric tons CH}_4 \end{aligned}$$

Source: CCAR 2008a, Equation III.8e, Methane Emissions from Distillate Fuel (Gallons), page 51

$$\text{Total CH}_4 \text{ from All Sources} = 4.67 \text{ metric tons CH}_4$$

Nitrous Oxide

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 0.0001 \text{ kg N}_2\text{O}/\text{MMBtu} \\ &x 788,400 \text{ MMBtu (natural gas)} x 0.001 \text{ metric tons/kg} = 0.0788 \text{ metric tons N}_2\text{O} \end{aligned}$$

Source: CCAR 2008, Equation III.8d, Nitrous Oxide Emissions from Natural Gas (MMBtu), page 51

$$\begin{aligned} \text{Total Emissions (metric tons)} &= 0.0001 \text{ kg N}_2\text{O}/\text{gallon} \\ &x 9,996 \text{ gallons (distillate fuel)} x 0.001 \text{ metric tons/kg} = 0.0010 \text{ metric tons N}_2\text{O} \end{aligned}$$

Source: CCAR 2008, Equation III.8e, Nitrous Oxide Emissions from Distillate Fuel (Gallons), page 51

$$\text{Total N}_2\text{O from All Sources} = 0.080 \text{ metric tons N}_2\text{O}$$

9.4.6 Step 6: Convert CH₄ and N₂O Emissions to CO₂-e and Sum All Subtotals

General Water District converted the total CH₄ and N₂O results from Step 5 to CO₂-e, then added them to the CO₂ emissions from Step 4 to determine the total CO₂-e produced by the facility. This example assumes use of GWP values from the SAR report.

Table 9.4
Total stationary combustion emissions

CO ₂ emissions (metric tons)	CH ₄ emissions (metric tons)	CH ₄ CO ₂ -e emissions (metric tons)	N ₂ O emissions (metric tons)	N ₂ O CO ₂ -e emissions (metric tons)	Total CO ₂ -e emissions (metric tons)
41,934	4.67	98	0.08	25	42,057

CHAPTER 10

UNIQUE EMISSION SOURCES

Some GHG emission source types are unique to the water industry. While it is the conclusion of this project team that the small magnitude of emissions from these sources will not significantly affect the total emissions of a water utility, and thus the need for registries to support quantification protocols specific to the water industry does not exist, information will still be required to quantify and document these small sources. This section addresses those emission sources that are somewhat unique to water utilities and provides guidance on how to calculate the resulting emissions. In some cases, these sources may represent Scope 3 emissions for the water utility.

Unique emission sources include, but are not exclusive to, the use of ozone, GAC regeneration, land use, solids disposal, and biological denitrification. Also, for utilities that own raw water storage such as dams and reservoirs, it may be important to consider the effects of eutrophic conditions on the environment. The following information should be available to calculate emissions from these sources: amount of ozone generated and type of ozone generation system; amount, type, and disposal location for solids; inventory of utility's land holdings; and information concerning the source of the plant's water.

This chapter is intended primarily to provide quantification techniques for these source types. Issues regarding handling of Scope 3 emission sources, and in particular impact of water conservation projects, are included in Chapters 6 and 11 of this document.

10.1 EMISSIONS FROM OZONE

GHG emissions from ozone are limited to air-based systems. Ozone is generated by passing oxygen through an electric field, that is, corona discharge, where O₂ is broken into O and recombined as O₃. During the ozone generation process, N₂O is produced in small quantities as well due to the presence of nitrogen from ambient air. If ozone is generated from pure oxygen, the emissions associated with it are *de minimus* (Wheale 2008).

To calculate the emissions from ozone, the volume of ozone that the plant uses is needed. The calculation for N₂O emissions from an air-based ozone generation system is as follows (UKWIR 2008):

$$\text{Emitted } N_2O = \text{Volume Ozone (m}^3\text{)} * 0.00011 \text{ kg } N_2O/\text{m}^3 \text{ Ozone}$$

10.2 EMISSIONS FROM GRANULAR ACTIVATED CARBON REGENERATION

On-site GAC regeneration can be a significant source of GHGs. Two factors are considered during GHG calculations for GAC regeneration: 1) energy used for the thermal regeneration process, and 2) GAC losses associated with the process (Liu and Wagner 1985).

Most on-site GAC regeneration systems use natural gas as their fuel source. If a meter is dedicated to the fuel line, it is possible to calculate emissions based on natural gas usage. If the natural gas meter is use for multiple purposes, for example, for building heating, this consumption would have to be removed from the overall usage to prevent double-counting of emissions. If the direct fuel consumption is not known, it is possible to estimate emissions by

using the emission factors shown below. These emission factors are based on regeneration energy of 6,000 Btu/lb GAC when produced in a multi-hearth furnace, with 7.5 percent make-up carbon to account for losses during the regeneration process.

$$\text{Emitted } CO_2 = \text{GAC (ton)} * 1761.66 \text{ lb } CO_2/\text{ton GAC regenerated}$$

$$\text{Emitted } CH_4 = \text{GAC (ton)} * 0.20 \text{ lb } CH_4/\text{ton GAC regenerated}$$

$$\text{Emitted } N_2O = \text{GAC (ton)} * 0.01 \text{ lb } N_2O/\text{ton GAC regenerated}$$

It is also important to account for the emissions resulting from oxidation of the lost carbon. When the carbon is burned in the furnace, the 7.5 percent carbon that is lost during the regeneration process is oxidized into CO_2 and released into the atmosphere. Calculating the total CO_2 emissions from the oxidation process is performed using a simple mass balance equation as shown below.

$$\text{Emitted } CO_2 = 44 \text{ (MW of } CO_2) / 12 \text{ (MW of C)} * 7.5\% \text{ (% GAC lost)} * \text{ton GAC}$$

10.3 EMISSIONS FROM LAND USE

Management of land owned by water utilities may create GHG emissions; create carbon uptake, or reduce the emission of non- CO_2 GHGs depending on the land use. For example, third-party grazing of cattle on utility-owned lands would cause CH_4 emissions from enteric fermentation in the digestive system of cattle, and fertilizer application practices can cause emissions of N_2O . Increase to vegetation density or soil carbon content can cause a net removal of CO_2 from the atmosphere. Emissions from land management are typically outside of the boundaries of a Scope 1/Scope 2 emission inventory, and for most water utilities, agricultural activity on utility-owned lands would be under the control of a tenant organization. Due to these factors, quantification of emissions from land management is outside of the scope of this document. The reader should be aware, however, that options may exist to reduce or sequester GHGs based on changes in land management, and this should be considered as an option in the context of the management strategies discussed in Chapter 11.

10.4 ALLOCATING EMISSIONS FROM WATER SOURCES

Standing water can be viewed as a potential emission source especially if the water body is eutrophic. When a dam or reservoir is created, the lack of movement in the water can result in both CH_4 and CO_2 emissions from the surface. No systematic way of assessing emissions to a reservoir is available because the process is dependent on factors that vary. Therefore, some reservoirs will have a very small amount of GHG emissions while others could have significant emissions. Still, it is recommended that the values in Table 10.1 are used as a reference to roughly estimate the emissions of a source body of water based on its surface area. Reservoir locations are broken down by temperature into boreal, subtropical, temperate, and tropical

Table 10.1
Emission estimates based on reservoir location (mg/m²/day)

	CO₂	CH₄	N₂O
Boreal	1,460	57.2	0.2
Subtropical	525	6.7	0.0
Temperate	525	6.7	0.0
Tropical	5,470	136.1	218.8

Source: Varis, et al. 2007

categories. Once the category into which the reservoir falls is determined, the emissions can be calculated based on the total surface area of the water body (Varis, et al. 2007).

10.5 ALLOCATING EMISSIONS FROM SLUDGE DISCHARGE

This section estimates GHGs resulting from solids disposal from a water treatment plant. Emissions from solids can vary significantly with the organic levels from the source water and solids treatment processes, and should typically be considered on a case-by-case basis. However, it is possible to simplify solids emissions by considering all solids as aerobic sludge, similar to wastewater sludges. Aerobic sludge emits GHGs when sent to landfills, and these emissions must be counted. The UKWIR provides the following simple calculations to account for a plant's solids emissions using total organic carbon (TOC) (UKWIR 2005):

$$Emitted\ CO_2 = Mass\ TOC\ removed\ (ton) * 762kg\ CO_2/ton\ landfilled$$

$$Emitted\ CH_4 = Mass\ TOC\ removed\ (ton) * 39kg\ CH_4/ton\ landfilled$$

When attempting to estimate the mass of TOC removed, one method a utility might consider is calculating the TOC in mg/L of the raw water and the TOC in mg/L of the finished water. The difference of these two values is an approximation of the mass of TOC removed.

10.6 BIOLOGICAL DENITRIFICATION

Biological denitrification for water can be full stream or split stream. In either case, the denitrification is necessarily complete (that is, less than 1 mg/L nitrate after treatment). This is necessary to ensure that nitrite will not be present in the water. Complete denitrification is accomplished by supplying sufficient organic matter to allow the reactions to continue to completion. This is achieved with approximately 4 mg/L chemical oxygen demand (COD) to 1 mg/L nitrate (Hiatt and Grady, Jr. 2008). Rittmann (2001) observed that, as long as all dissolved oxygen (DO) was satisfied, no N₂O would be formed during denitrification. If it is estimated that there is insufficient organic matter, the N₂O emissions can be estimated at approximately 30 percent of the total nitrogen gas produced as shown in the equation below.

$$Emitted\ N_2O = Mass\ N\ removed\ (kg) * 0.3$$

For complete nitrate removal the following equation would be used.

$$\textit{Emitted } N_2O = \textit{Mass N removed (kg)} * 0.01$$

This last calculation can also be considered *de minimus*.

CHAPTER 11 MANAGEMENT STRATEGIES

Water utilities can employ a number of methods to reduce the direct and indirect impacts of their operations on GHG emissions. This section presents a framework of opportunities and issues to consider.

On the one hand, management strategies for responding to climate change should consider adaptation to the anticipated effects. A recently published report by the U.S. Climate Change Science Program (2008) indicates, on average, precipitation is likely to be less frequent but more intense, and precipitation extremes are very likely to increase. For example, for a mid-range emission scenario, daily precipitation, so heavy that it now occurs only once every 20 years, is projected to occur approximately every eight years by the end of this century over much of Eastern North America. Impacts from projected climate change also include reduced soil moisture and increased evapotranspiration, reduced snowpack storage, and increased extreme weather events (IPCC 2007). Utilities should assess the risk of climate change to quantity and quality of water supplies and the ability of infrastructure to accommodate such fluctuations (AMWA 2007). Structured climate risk assessments are useful in understanding water system sensitivity, vulnerability, and adaptive capacity. These assessments highlight system vulnerabilities and can result in the development of approaches to manage residual risks. A total water management planning process can then be used to develop a holistic approach to operation and improvement of supply systems. In addition to the above referenced documents, the following literature may be of value:

- Preparing for Climate Change, A Guidebook for Local, Regional, and State Governments (Center for Science in the Earth System (The Climate Impacts Group), Joint Institute for the Study of the Atmosphere and Ocean, University of Washington, and King County, Washington. 2007.)
- Handbook on Methods for Climate Change Impact Assessment and Adaptation Strategies (Feenstra, Jan F., Ian Burton, Joel B. Smith, Richard S.J. Tol, eds. 1998. United Nations Environment Programme.)
- Climate Change and Water Resources: A Primer for Municipal Water Resources (Miller, Kathleen and David Yates. 2006. Denver, Colo.; AwwaRF and AWWA.)
- Understanding and Responding to Climate Change. (National Academy of Sciences. 2005.) http://dels.nas.edu/dels/rpt_briefs/climate-change-final.pdf.
- Incorporating Climate Change in Water Planning (Freas, et al. 2008. *Journal AWWA*, 100:6)

On the other hand, management strategies should engage mitigation. Such opportunities can generally be divided into two primary categories: internal and external projects. Internal projects would reduce GHG emissions directly from utility operations or result in the sequestration of carbon from the atmosphere using utility-owned land or facilities. External projects would reduce GHG emissions or result in sequestration from facilities or land owned by third parties. Such external projects may or may not be credited against a utility's emission profile, depending on the guidelines of the registry or regulatory program and the characteristics of the reduction; see the discussion below for more information regarding the ability of organizations to claim such reductions against their inventory.

As noted elsewhere in this document, water utility GHG emissions may vary significantly from year to year based on hydrologic conditions affecting gravity flow of source water, availability of hydro electric power, and other factors. These impacts will likely be a factor on the management strategy and selection of the portfolio of reduction opportunities.

11.1 INTERNAL REDUCTION OPPORTUNITIES

Opportunities exist for the mitigation and reduction of Scope 1 or Scope 2 emissions, and for the creation of offset projects that could be credited against a utility's Scope 1 emissions. At least three categories of mitigation opportunities exist: reduction of energy use in existing operations, construction of renewable energy projects that result in the mitigation of GHG emissions, or development of projects that offset emissions through the sequestration of carbon or other actions.

Reduction of energy use through existing operations may cause reduction in stationary or mobile combustion fuel consumption, thus reducing Scope 1 emissions, or reduction in electrical usage, thus reducing Scope 2 emissions. Increasing energy efficiency in utility buildings, development of combined heat and power (CHP) projects for electricity generation and space heating, replacing fleet vehicles with more energy efficient vehicles, and managing fleet logistics to reduce miles driven are three example opportunities to reduce fuel consumption. Changes to water supply sources may decrease transport or treatment power, and customer water conservation may reduce both internal and external energy consumption.

An effective energy management strategy not only reduces operating costs but can also reduce a utility's carbon emissions. There are no-cost options, such as optimizing pumping schedules to a finished water storage tank to prevent unnecessary pump usage. Low-cost options include installing motion sensors in all buildings so that no rooms are lit unnecessarily. There are higher-cost options as well, such as building new pumping and storage facilities to reduce pumping requirements or installing more energy-efficient treatment technologies. Additional mitigation techniques include installation of "green" power, such as photovoltaic and wind turbine power, to offset brown power utilization. "Brown" power is considered power generated by previously typical sources, including coal and other fossil fuels.

Working with employees and other departments or agencies for offsets and efficiencies may be available as well including, for example, reduced park landscape irrigation or employee incentives for reducing carbon footprint. All of these options have the same goal: to reduce energy consumption in an effort to reduce operating costs and/or GHG emissions. As this is such an important strategy for water utilities to employ, there is an abundance of sources available to offer solutions and energy management ideas. The list in section 11.6 provides some of these available resources.

Increased onsite generation of renewable energy may also be used to reduce Scope 2 emissions, and potentially, Scope 1 emissions if alternative heat or power systems can be used to replace fossil fuel use. New or more efficient hydropower, wind, solar photovoltaic, and biomass electrical generation are examples to consider. If the resulting power is consumed by the utility, then it may result in a reduction of fossil-fuel based power purchased from the grid, thus resulting in Scope 2 emissions reduction. If the resulting power is sold to an electric utility, or if the "green" attributes of the power are conveyed to other entities through the sale of RECs or other third party contractual arrangement, then as noted in Chapter 6 this will likely not be credited to the utility as a Scope 2 emission reduction. Other opportunities for Scope 1 emission

reduction may exist such as use of biomass to generate steam for space heating, use of biofuels such as ethanol or biodiesel in vehicles, use of lower carbon fossil fuels such as compressed natural gas in motor vehicles, or use of waste heat or chemical energy from a neighboring industrial facility to displace existing fuel consumption.

Regarding biofuels, as noted in Chapters 8 and 9 of this document, the reader is strongly cautioned to remain informed of the ongoing debates regarding the net environmental and social impacts, including GHG emissions, water consumption, food pricing and shortages, and other issues, associated with the production and use of the biofuel. In particular, the production and use of corn-based ethanol has been questioned by environmental groups, while consensus seems to exist that cellulosic ethanol has greater environmental benefits. By most protocols, fuel switching from fossil fuels to biofuels would reduce Scope 1 emissions for the entity in question, but water utilities are advised to make their own assessments regarding life-cycle impacts, and whether the fuel switching simply shifts GHG emissions to the entity producing the fuel.

Carbon offset project opportunities include reforestation or afforestation of utility-owned lands, soil or wetland management projects that result in increased carbon storage, and the management of fertilizer application to reduce N₂O emissions. Significant domestic and international research is ongoing to develop technology for the capture of CO₂ from industrial facilities such as power plants; for transport and storage of CO₂ in geologic reservoirs such as deep saline aquifers, unmineable coal seams, organic rich shales, or basalt formations; or for use of the CO₂ for enhanced oil or gas recovery. While the magnitude of carbon capture and storage (CCS) projects may be beyond the financial and technical capability of most water utilities, and because water utilities often do not own and operate the type of facilities from which carbon capture would be practical, it may be possible for utilities to take a partial equity position in CCS systems as external projects.

11.2 EXTERNAL PROJECT OPPORTUNITIES

A number of market drivers for the viability of external offset projects exist. Internal energy efficiency projects will allow fractional reduction of GHG emissions, but cannot completely eliminate, total utility GHG emissions. External projects that result in the creation of carbon offsets would be required for most water utilities to approach “carbon neutral” or “carbon negative” status. As the market evidence has shown, external projects may actually provide creditable reductions at much lower cost to the buyer than some capital-intensive internal projects. For example, consumer water conservation projects may be easily influenced by water utilities, and provide opportunity for low-cost GHG emission reductions outside of the organizational boundaries of the utility, although rights to claim ownership of those reductions would be a significant issue, as has been discussed previously. Moreover, external projects frequently offer ancillary environmental benefits such as reduced emissions of criteria or toxic air pollutants, and improvement of ecosystem habitats (such as in a reforestation project).

External offset opportunities include projects directly funded, developed, and operated by the utility, in addition to the actual purchase of carbon offsets, RECs, or other instruments on the open market. The following discussion describes specific types of reduction opportunities, followed by a discussion of issues regarding purchase of instruments.

The types of external offset projects are similar to internal projects open to utilities, although a few additional opportunities exist. Projects that could be created or for which offsets

could be purchased include the following categories; it should be noted that neither the categories nor the examples provided for each category are a comprehensive list:

- Water conservation programs. As noted elsewhere in this document, conservation by a water utility's consumers will directly reduce the Scope 1 and Scope 2 emissions of the utility. However such programs could also create emission reductions for the water consumer, upstream water suppliers, wastewater treatment plants, and other entities. Utilities are encouraged to become active in encouraging water conservation by consumers and influencing regulations regarding water use efficiency for new industrial and commercial development.
- Energy efficiency projects. A few examples of this broad category include providing financial assistance to local school districts or other public entities with energy efficient lighting or support for water consumers by installing more efficient water heating equipment. Internationally this could include assistance for entities in developing countries with modernization of electrical generation facilities or transmission systems. Especially where the project creates an external reduction in electrical power consumption, caution should be used regarding ownership of the reduction; a dispute may arise regarding whether claim to the reduction is owned by the entity funding the project, the entity for which Scope 2 emissions were reduced, or the electric utility actually emitting the Scope 1 emissions resulting from the power generation.
- Renewable energy generation. RECs typically convey the right to claim the environmental attributes of "green" power generation, even if that generation occurs in locations distant from the purchaser of the REC, and again serves as a means of promoting investment in such projects. Caution is warranted where the transfer of RECs is involved. Many registry programs accept RECs as potential offsets of Scope 2 GHG emissions; however, this is a source of continued debate in the technical community. More information on RECs is included below.
- Land Use, Land Use Change, and Forestry (LULUCF) Projects. These projects include management of N₂O emissions and carbon uptake in soils from agricultural projects or wetlands, reforestation, afforestation, and so on. These projects could be created domestically or internationally. Caution is again advised, as the validity of many such projects has been called in question by various certifying agencies in the past few years, and permanence of the reduction, "leakage" of emissions or shifting of the activity to other areas, and accurate definition of project baselines are major issues.
- CH₄ emissions reductions. These reductions can include capture-and-destruction or conversion-to-energy of CH₄ from landfills, wastewater treatment plants, coal mines, or livestock operations; reduction of natural gas pipeline leakage; and improvement of flare efficiency at refineries.
- High-GWP gas reduction/destruction. These projects could include reduction of PFC emissions from aluminum or chemical manufacturing plants; reduction of CFC, HCFC, PFC, or HFC emissions from refrigeration systems; and reduction of SF₆ emissions from the utility industry.

- CCS projects. While carbon storage would technically include forestry and other terrestrial sequestration projects, here CCS refers to capture of CO₂ from power plants, fertilizer manufacture, and other sources combined with geologic storage, solid phase mineralization, biomass production (including possible biofuel production through feeding of algae), ocean sequestration, and so on.

Note that the UNFCCC CDM has a list of pre-approved project quantification methodologies that provides additional examples of project types.

As noted above, the projects described could be developed either with or without the intent to create offsets for credit against the emission profile of the creating entity. Where offsets are intended, a series of tests including verification of financial, regulatory, and common practice additionality will be required, as will definition of a baseline scenario against which the project impacts are measured. Monitoring and verification of actual reductions will be necessary, and engagement of a third-party verification organization may be required by the registry or regulatory agency to which emissions are reported. However, even if offsets are not to be created and claimed, third-party verification or registration of both internal and external projects may be advisable to increase credibility of the actions taken.

Carbon offsets are transferable instruments or commodities created to allow transfer of the right to claim a project-based GHG reduction, and they are a means of allowing external investment in projects that would often not otherwise occur. Offsets can be categorized into compliance instruments (for example, a CER registered under the CDM, for use by entities in meeting Kyoto Protocol-related obligations) or voluntary/over-the-counter (OTC) instruments that are targeted toward entities pursuing reductions for other reasons. For compliance instruments, the guidelines and requirements of the mandatory program will detail the eligibility of various project types and will specify the certification procedures needed. For OTC instruments, various emerging guidelines, including the Voluntary Carbon Standard, WRI/WBCSD GHG Protocol for Project Accounting, and ISO 14064-2 and 14064-3 standards, can be used as a basis for quantification and verification of the GHG reduction. Either type of instrument can typically be created and certified for a particular project, purchased from various brokers (such as Natsource, Evolution Markets, and Ecorescurities), or purchased from various registries or trading platforms (such as CCX, Voluntary Carbon Registry, and World Energy).

RECs typically convey the right to claim the environmental attributes of “green” power generation, even if that generation occurs in locations distant from the purchaser of the REC, and again serves as a means of promoting investment in such projects. Many registries have accepted the use of RECs as carbon reduction instruments, with the conversion from kWh of renewable power to tons of CO₂-e reduction based on the attributes of grid electrical power in the location where the REC was generated. However, this continues to be a source of disagreement and debate, in particular because certification of a REC does not require the same additionality tests as other types of carbon offsets. Currently, RECs can be purchased through various brokers on the open market.

11.3 OWNERSHIP ISSUES FOR SCOPE 3 EMISSION REDUCTIONS

As noted above, in some circumstances the most cost effective GHG emission reduction opportunities available to water utilities may actually reduce the Scope 1 direct or Scope 2 indirect emissions of other entities, and as such would represent a reduction to Scope 3 optional

indirect emission for the utility. While such programs represent strong environmental stewardship, a number of challenges exist in obtaining “ownership” of such reductions.

A key example is in the support of water conservation programs in the community, including education and outreach, as well as financial assistance for the use of water conserving hardware and appliances by residential customers. Such projects would likely reduce the water utility’s Scope 1 and Scope 2 emissions, because less water would be pumped and treated, however substantial savings could also be realized by other parties through reduced fuel combustion for water heating, and reduced electrical consumption for transportation of that water outside of the utility’s boundaries.

In circumstances where a water utility may subsidize the purchase and installation of water conserving hardware, it may be possible to use a simple contract with the water consumer to transfer ownership of any such reduction to the utility. This would be analogous to programs where electric utilities are able to satisfy some of their renewable portfolio standard obligations by subsidizing installation of solar generation by homeowners. It would be difficult however for water utilities to accurately assess the emission reduction impact of such individual actions, and absent a regulatory or contractual basis, the right to claim the reduction would remain with the party actually emitting the GHGs.

More problematic, especially under mandatory reporting or cap-and-trade programs, is the ability to claim ownership of GHG reductions from electrical savings of such projects. In this case, three parties are involved with the reduction—the water utility, the entity owning the upstream or downstream pumping or electrical heating equipment, and the electric utility that supplies the power. Clearly the ultimate reduction to Scope 1 emissions occurs at the electric utility. It would likely be very difficult to develop a contractual basis which would allow the water utility to claim such a reduction against its own obligations. Furthermore, it is unlikely that such a specific situation could be addressed in future regulations even if water utilities advocate or lobby for such conditions.

There may be opportunity for water utilities, wastewater treatment entities, and energy providers to collaborate on water conservation programs. Clearly such actions would reduce financial burdens, energy consumption, and GHG emissions for all three groups of parties. As such, on a case-by-case basis, it may be possible to develop agreements regarding ownership of resulting reductions, and identification and transfer of offsets to the parties funding the reduction on for example a pro-rated basis. No such precedent exists to the knowledge of the authors of this document, but such agreements are not unrealistic.

Another area for possible action and advocacy by water utilities is in regards to potential distribution of revenues from GHG cap-and-trade programs back to the community to support GHG reduction projects. For example, in initial discussions of energy and climate policy, the Obama administration has suggested that a portion of receipts of allowance auctions be used to support development of clean energy, investment in energy efficiency improvements, and support of the development of next generation biofuels and clean energy vehicles. While it may be impossible for water utilities to directly claim GHG reductions from water conservation or similar programs, it may be possible to obtain state or federal financial assistance from GHG allowance revenues to support those actions.

11.4 POTENTIAL VALUE OF GHG REDUCTION PROJECTS

A host of regulations are currently under development on a federal, state, and regional basis for cap-and-trade systems to limit GHG emissions. The value of internal or external projects to comply with regulatory compliance requirements is clear, and compliance will likely become a primary demand driver for such projects.

Meanwhile, voluntary actions convey a number of real benefits to the project proponent. Such benefits include, but are not limited to, the following considerations:

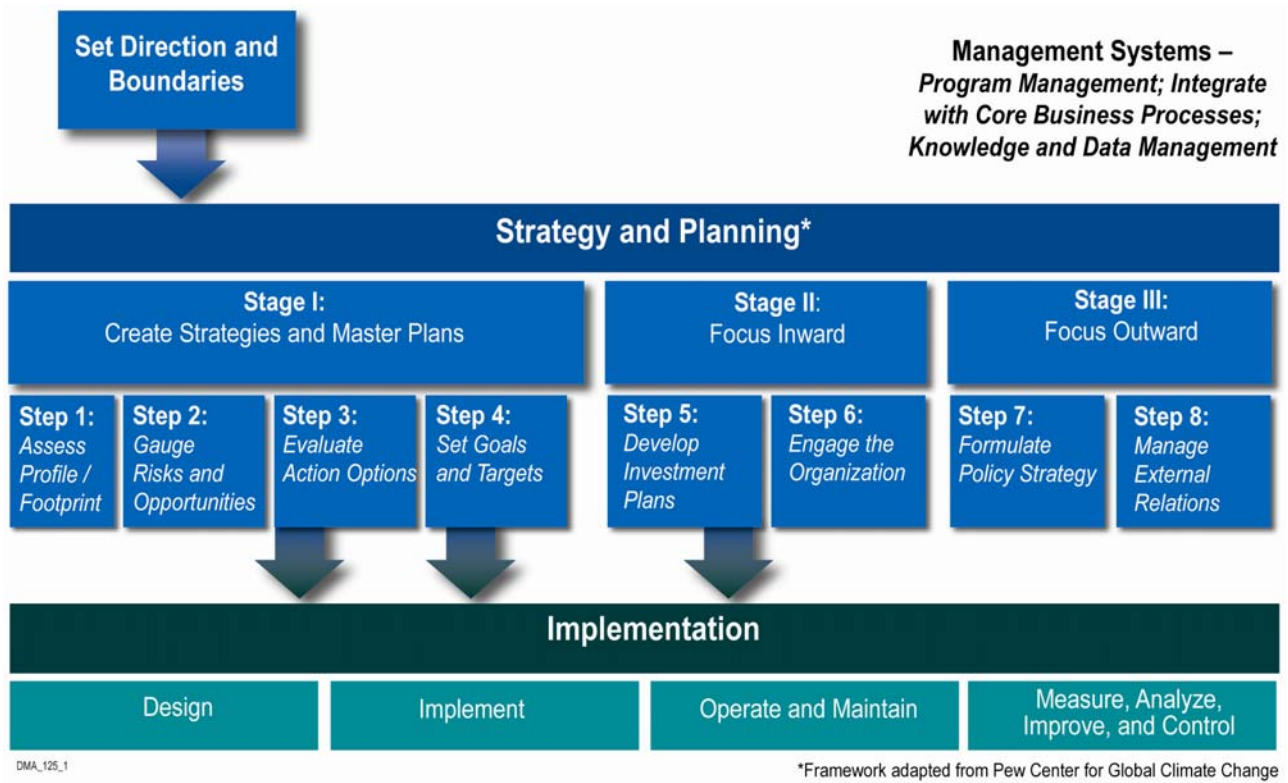
- Direct monetary benefit, in cases where offsets are created and sold on the market. Note that monetary value of offsets, considerations regarding whether market value depends on ancillary environmental or social benefits, and variation in value based on specific project type will vary considerably from market to market. More variation of this type in value is expected in the voluntary markets versus compliance markets.
- Improved relations with shareholders and the public, and stakeholder goodwill.
- In the case of energy efficiency projects, often a financial benefit can result from the reduced cost of energy.
- Market positioning for future regulatory programs—identification and development/acquisition of reductions that may provide ongoing offsets, increased knowledge of staff regarding methods for management of carbon emissions, and emissions intensity status for comparison against developing standards.
- Under some scenarios, such voluntary reductions may be eligible for early action credit against future regulatory obligations.
- Programs for addressing sustainability, including climate change and GHG emission mitigation, are important issues for some employees, and proactive management of such issues can assist in attracting and retaining talent.

11.5 STRATEGY DEVELOPMENT AND SELECTION OF OPTIONS

Figure 11.1 provides a roadmap for development and implementation of an overall climate change strategy (Pew Center on Global Climate Change 2006). This roadmap can be used to assess both mitigation and adaptation strategy. After assessment of a utility's existing emissions profile and footprint, risks and opportunities can be assessed, action items identified and evaluated, and goals and targets for emission reductions and infrastructure improvements set. After creation of a carbon strategy, investment plans can be developed and vetted within the organization. Externally, given knowledge of practical actions, organizations can become involved in policy development, and messages regarding position and intended actions can be externally communicated.

Specific to analysis and selection of options for emission reductions, a number of considerations are relevant:

1. The portfolio of potential internal projects can be brainstormed after the emission profile is assessed, and types of external projects that would be favored can be identified.
2. Tangible and intangible ancillary benefits should be listed, for example, ecosystem restoration or reduced emission of air pollutants.



Source: Pew Center on Global Climate Change 2006.

Figure 11.1. Roadmap for development and implementation of an overall climate change strategy

3. Total cost and normalized cost (\$/ton CO₂-e) should be determined for each option.
4. Potential risk factors, including those from project development, cost, credibility, and reliability should be identified for each considered option.
5. Opportunities for partnership with other entities (for example, investment bankers or co-developers) should be identified for options that may exceed funding capability or risk tolerance.
6. Decision analysis methods can then be used to identify the actions or group of actions that are achievable to reach a pre-determined reduction target, or reduction targets can then be set based on the cumulative benefits of chosen projects.

Development and implementation of an effective climate change strategy requires assessment of current emission profiles; assessment of risks and opportunities considering current regulatory scenarios and mechanics of future cap and trade systems; identification, evaluation, and prioritization of actions for internal and external action for emission reduction or offset; securement of funding to implement selected actions; and external communication of goals, achievements, and policy needs. Clear planning of these steps can maximize the effectiveness of capital and operational investments in mitigation of water utility's impacts on climate change.

11.6 ENERGY MANAGEMENT RESOURCES

The resources listed in this section provide information on numerous ways to mitigate GHG emissions through reduced energy use. In addition to operation and management strategies for specific utility facilities and utility operation and management, water efficiency and the costs and benefits associated with energy management are also included.

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GLOSSARY

Absolute-based emissions	Absolute emissions are simply the sum of emissions from all sources identified within the organizational and operational boundaries.
Adaptation	Initiatives and measures to reduce the vulnerability of natural and human systems to actual or expected climate change effects. Various types of adaptation exist, e.g. anticipatory and reactive, private and public, and autonomous and planned. Examples are raising river or coastal dikes, the substitution of more temperature-shock resistant plants for sensitive ones, etc.
Additionality	Additionality is a concept from international GHG project accounting principles that requires that a project activity would not have occurred in the absence of a market for GHG emission reductions. Many protocols ensure that projects are additional by setting a performance standard that project activities reduce GHGs significantly more than standard practice in an industry and are not driven by regulatory or other requirements. Such performance-based project protocols are a well-recognized and accepted approach adopted by the International Standards Organization, TCR, CCAR, the WRI/WBCSD International GHG Protocol, and others.
Afforestation	Direct human-induced conversion of land that has not been forested for a period of at least 50 years to forested land through planting, seeding and/or the human-induced promotion of natural seed sources. See also Re- and Deforestation.
Anthropogenic	Resulting from or produced by human actions.
Baseline scenario	The emissions that would have occurred if not for the project that is being considered to generate offsets.
Benchmarking	The process of setting the baseline GHG inventory, and understanding the existing GHG emissions from various categories of emissions throughout the organizational structure. After benchmarking, utilities may choose to compare their emissions totals with other organizations.

Biofuel	Any liquid, gaseous, or solid fuel produced from plant or animal organic matter e.g. soybean oil, alcohol from fermented sugar, black liquor from the paper manufacturing process, wood as fuel, etc. Second-generation biofuels are products such as ethanol and biodiesel derived from ligno-cellulosic biomass by chemical or biological processes.
Biogenic	Resulting from or produced by biological processes.
Biomass	The total mass of living organisms in a given area or volume; dead plant material can be included as dead biomass.
Cap and Trade	A cap and trade system is a market-based regulatory system in which a government entity caps the total emissions from a group of GHG sources. Each source is given or allowed to purchase a number of allowances with the total number of allowances issued being equal to the cap. The number of allowances issued declines each year. The sources are then permitted to trade among themselves. Those that have made deeper reductions can sell their allowances to other sources that have made fewer reductions. In some cap and trade systems, the sources are also allowed to purchase reductions that are made by projects in unregulated sources outside of the system.
Carbon cycle	The set of processes such as photosynthesis, respiration, decomposition, and air-sea exchange, by which carbon continuously cycles through various reservoirs, such as the atmosphere, living organisms, soils, and oceans.
Carbon neutral	Carbon neutral means that an organization has inventoried the GHG emissions associated with their activities, reduced those emissions to the maximum extent feasible, and offset their remaining unavoidable emissions by purchasing and retiring verified GHG emission reductions.
CARROT	The Climate Action Registry Reporting Online Tool is the California Registry's greenhouse gas emission calculation and reporting software.
CO ₂ Equivalent	CO ₂ -e, that is, a measure of specific GHG emissions, as expressed in carbon dioxide equivalents; the amount of CO ₂ emission that would cause the same radiative forcing as an emitted amount of a well mixed greenhouse gas, or a mixture of well mixed greenhouse gases, all multiplied with their respective Global Warming Potentials to take into account the differing times they remain in the atmosphere.

Climate change	As defined in the IPCC AR4 report, climate change refers to any change in climate over time, whether due to natural variability or as a result of human activity.
CNG	Compressed natural gas, that is, natural gas that has been compressed under high pressures, typically between 2000 and 3600 psi, and held in a container.
CRIS	Climate Registry Information System, a tool used by the Climate Registry to calculate GHG emissions.
<i>de minimus</i>	The expression <i>de minimis</i> is of Latin origin meaning, “of little importance” or “at a level that is too small to be concerned with.” For GHG inventory reporting, <i>de minimis</i> is used to reference sources within the inventory that are small and/or negligible in comparison to the overall inventory and for which rigorous supporting data and documentation may not be warranted.
Deforestation	The natural or anthropogenic process that converts forest land to non-forest. See afforestation and reforestation.
Emission factors	An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed, and is reported in pounds or kilograms per kilowatt-hour (lbs/kWh or kg/kWh) of use.
Emissions trading	A market-based approach to achieving environmental and air quality objectives. It allows those reducing GHG emissions below their emission cap to use or trade the excess reductions to offset emissions at another source inside or outside the country. In general, trading can occur at the intra-company, domestic, and international levels. The Second Assessment Report by the IPCC adopted the convention of using permits for domestic trading systems and quotas for international trading systems. Emissions trading under Article 17 of the Kyoto Protocol is a tradable quota system based on the assigned amounts calculated from the emission reduction and limitation commitments listed in Annex B of the Protocol.
Footprint	The term “footprint” has been used widely within the GHG management community, and no common definition or use of the term exists. For the purpose of this document and to assist water utilities in management strategy development, the term is used to indicate the total life-cycle GHG impacts of water supply, transport, treatment, and use.

Fugitive Emissions	Fugitive sources of emissions are the result of unintentional leaks or releases from a process or as a result of material usage within operations.
GHG Protocol	A publication by World Resources Institute that is the primary reference for GHG documentation; see Chapter 3.
Global warming	Global warming refers to the gradual increase, observed or projected, in global surface temperature, as one of the consequences of radiative forcing caused by anthropogenic emissions.
Global warming potential	Represents the heat-trapping ability of each GHG relative to CO ₂ .
Greenhouse effect	Greenhouse gases effectively absorb infrared radiation, emitted by the Earth's surface, by the atmosphere itself due to the same gases and by clouds. Atmospheric radiation is emitted to all sides, including downward to the Earth's surface. Thus, greenhouse gases trap heat within the surface-troposphere system. This is called the greenhouse effect. Thermal infrared radiation in the troposphere is strongly coupled to the temperature at the altitude at which it is emitted. In the troposphere, the temperature generally decreases with height. Effectively, infrared radiation emitted to space originates from an altitude with a temperature of, on average, -19°C, in balance with the net incoming solar radiation, whereas the Earth's surface is kept at a much higher temperature of, on average, +14°C. An increase in the concentration of greenhouse gases leads to an increased infrared opacity of the atmosphere and therefore to an effective radiation into space from a higher altitude at a lower temperature. This causes a radiative forcing that leads to an enhancement of the greenhouse effect, the so-called enhanced greenhouse effect.
Greenhouse gas	GHG, that is, a gas that promotes climate change, usually expressed in terms of tons of carbon dioxide; those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere and clouds. This property causes the greenhouse effect. Water vapor (H ₂ O), carbon dioxide (CO ₂), nitrous oxide (N ₂ O), methane (CH ₄) and ozone (O ₃) are the primary greenhouse gases in the earth's atmosphere. Moreover, there are a number of entirely human-made greenhouse gases in the atmosphere, such as the

halocarbons and other chlorine- and bromine-containing substances, dealt with under the Montreal Protocol. Besides carbon dioxide, nitrous oxide, and methane, the Kyoto Protocol deals with the greenhouse gases sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons.

Intensity-based emissions	Intensity-based emissions are expressed as a ratio of absolute GHG emissions per unit of production activity or economic output.
Inventory	An inventory will assess the emissions being generated within the organizational boundary; it does not represent the total life-cycle analysis carbon footprint of the organization for all upstream and downstream activities that comprise the entity's operations. A water utility's footprint will typically be far larger than a utility's inventory.
Kyoto 6	The six greenhouse gases cited by the Kyoto Protocol, including carbon dioxide [CO ₂], methane [CH ₄], nitrous oxide [N ₂ O], hydrofluorocarbons [HFCs], perfluorocarbons [PFCs], and sulfur hexafluoride [SF ₆].
Liquefied Natural Gas	LNG, that is, natural gas liquefied either by refrigeration or by pressure.
Mobile Combustion	Mobile emission sources include movable equipment and/or transportation vehicles/vessels that combust fuels to operate.
Offset	Carbon offsets are tradable commodities typically representing the reduction or sequestration of one metric ton of CO ₂ -e.
Process-Related Emissions	Process-related emission sources are the result of physical and/or chemical processes other than fuel combustion taking place within the entity operations.
Protocol	A guidance standard by which an entity can prepare a greenhouse emissions inventory, such as that espoused by the Climate Registry.
Reforestation	Direct human-induced conversion of non-forested land to forested land through planting, seeding and/or the human-induced promotion of natural seed sources, on land that was previously forested but converted to non-forested land. See also afforestation and deforestation.

Renewable Energy Credit	RECs are similar to carbon offsets, in that the value to claim the “green” attributes of a particular action can be sold on the market. RECs are typically sold in units of MW-hr of green power generation, and can be used in compliance markets by utilities needing to comply with an RPS but lacking sufficient internal or wholesale green power supply, or in the voluntary markets by entities wishing to claim the green attributes for other purposes.
Scope 1 emission	Direct emissions released by an entity within its organizational boundaries, including direct generation of power, stationary combustion, and mobile combustion.
Scope 2 emission	Indirect emissions associated with an entity within its organizational boundaries, including purchase of electricity.
Scope 3 emission	Optional Indirect GHG emissions are a broad category that cover all other releases that are an indirect consequence of the entity’s operations, or which could be within the sphere of influence of the entity.
Sequestration	Carbon storage in terrestrial or marine reservoirs. Biological sequestration includes direct removal of CO ₂ from the atmosphere through land-use change, afforestation, reforestation, carbon storage in landfills and practices that enhance soil carbon in agriculture.
Stationary Combustion	Stationary emission sources are those non-moving or fixed location pieces of equipment that combust fuels to produce steam, heat, power, or electricity at facilities within the organizational boundaries.
Voluntary carbon market	Markets in which businesses and consumers purchase and sell GHG reductions instead of directly reducing their own emissions

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ABBREVIATIONS

AR4	IPCC Fourth Assessment Report
Btu	British thermal unit(s)
CA	California
CARB	California Environmental Protection Agency, Air Resources Board
CARROT	Climate Action Registry Reporting Online Tool
CCAR	California Climate Action Registry
CCS	carbon capture and storage
CCX	Chicago Climate Exchange
CDM	Clean Development Mechanism
CEM	Continuous Emissions Monitor
CEMS	Continuous Emissions Monitoring System
CER	Certified Emission Reduction
CER	Corporate Environmental Reports
CFC	chlorofluorocarbon
CFI	Carbon financial instrument
CH ₄	methane
CHP	combined heat and power
CNG	compressed natural gas
CO ₂	carbon dioxide
CO ₂ -e	CO ₂ equivalent
COD	chemical oxygen demand
CRIS	Climate Registry Information System
CRT	Climate Reserve Tonnes
DO	dissolved oxygen
DOE	U.S. Department of Energy
EC	Electricity consumption
EF	emission factor
EIA	Energy Information Administration (of the DOE)
EIIP	Emissions Inventory Improvement Program
F&M	F&M Manufacturing
GAC	granular activated carbon
GHG	greenhouse gas
GHV	gross heating value
GRP	General Reporting Protocol
GWP	Global Warming Potential
HCFC	hydrochlorofluorocarbon
HFC	hydrofluorocarbon

HHV	higher heating value
Hp	horsepower
hr	hour
ICLEI	International Council for Local Environmental Initiatives
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
lb	pound
LNG	liquefied natural gas
LOX	liquid oxygen
LPG	liquefied petroleum gas
LULUCF	Land User, Land Use Change, and Forestry
MMBtu	million Btu
MMT	million metric tons
mpg	mileage per gallon
MT	metric tons
MW	megawatt, molecular weight
MWh	megawatt-hour
N ₂ O	nitrous oxide
NO _x	reactive nitrogen oxides (the sum of NO and NO ₂)
O ₃	ozone
ODC	ozone-depleting chemical
OTC	over the counter
PFC	perfluorocarbon
psi	pounds per square inch
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SAR	IPPC Second Assessment Report
SF ₆	sulfur hexafluoride
TAR	IPPC third assessment report
TCR	The Climate Registry
TOC	Total organic carbon
UKWIR	United Kingdom Water Industry Research Ltd

UNFCCC	United Nations Framework Convention on Climate Change
USEPA	U.S. Environmental Protection Agency
VCS	Voluntary Carbon Standard
WBCSD	World Business Council for Sustainable Development
WECC	Western Electric Coordination Council
WRF	Water Research Foundation
WRI	World Resources Institute