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Greenhouse Gas Mitigation Planning:

A Guide for Small Municipal Utilities

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Sponsored by
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Abstract

California's electric power generators are increasingly aware of the problem of greenhouse gas (GHG) emissions and their link to global climate change. Utilities anticipate a carbon-constrained future and want to prepare for this operational constraint by acting in an environmentally responsible, economically feasible and politically strategic manner through mitigating their GHG emissions. Information on the steps involved in, and the resources available for, GHG mitigation options have yet to be synthesized into a format that will help utilities make informed choices. Furthermore, utilities need to become familiar with the characteristics of the climate change problem as well as the variables, uncertainties, and potential costs and benefits of specific GHG mitigation options. To address this need, we have developed a GHG mitigation guide for a sub-sector of California's power generators: small municipal utilities. This guide is designed to help small municipal utilities navigate the decision-making process involved in choosing mitigation projects for implementation. This guide also outlines the types of information that need to be synthesized and the resources available for a utility to implement an economically and environmentally beneficial mitigation plan. The City of Burbank Water and Power (BWP) serves as a case study to illustrate the decision points necessary for forming a GHG mitigation plan.

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ACRONYMS & ABBREVIATIONS

AR	Afforestation/Reforestation
AWEA	American Wind Energy Association
BTU	British Thermal Unit
BWP	Burbank Water and Power
C	Carbon
CA	California
CARROT	Climate Action Registry Reporting Online Tool
CCAR	California Climate Action Registry
CCX	Chicago Climate Exchange
CDM	Clean Development Mechanism
CEC	California Energy Commission
CEMS	Continuous Emission Monitoring System
CO_2	Carbon Dioxide
CH_4	Methane
CPT	Cost Per Ton
DOE	United States Department of Energy
ECBM	Enhanced Coal Bed Methane Recovery
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
ERCs	Emission Reduction Credits
EU ETS	European Union Emissions Trading Scheme
GHG	Greenhouse Gases
Gt	Gigaton
GtC	Gigatons of Carbon
IGCC	Integrated Gasification Combined Cycle
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IPP	Intermountain Power Project
JI	Joint Implementation
kcf	Thousand Cubic Feet
kW	Kilowatt
kWh	Kilowatt Hours
lbs	Pounds
LULUCF	Land use, Land-use Change, and Forestry
Mha	Megahectare
MMT	Million Metric Tons
MT	Metric Ton
MTCE	Metric Ton of Carbon Equivalent
MMTCE	Million Metric Tons of Carbon Equivalent
MMBTU	Million British Thermal Units
Mt	Megaton
MW	Megawatt
MWh	Megawatt hour
N_2O	Nitrous Oxide
NEG/ECP	New England Governors and Eastern Canadian Premiers
n.d.	no date available
PUC	Public Utilities Commission
PV	Photovoltaic
QA/QC	Quality Assurance / Quality Control
QMV	Quantification, Monitoring and Verification
SCPPA	Southern California Public Power Authority
SOC	Soil Organic Carbon
Tm^3	cubic terameters (10^{12} meters)
tC/ha/yr	Tons of Carbon Per Hectare Per Year
UNFCCC	United Nations Framework Convention on Climate Change
U.S.	United States
w/w	By Weight

Table of Contents

EXECUTIVE SUMMARY

California's electric power generators are increasingly aware of the problem of greenhouse gas (GHG) emissions and their link to global climate change. Utilities anticipate a carbon-constrained future and want to prepare for this operational constraint by acting in an environmentally responsible, economically feasible and politically strategic manner through mitigating their GHG emissions. Information on the steps involved in, and the resources available for, GHG mitigation options has yet to be synthesized into a format that will help utilities to make informed choices.

The Greenhouse Gas Mitigation Planning Guide (Guide) addresses this need for a sub-sector of California's power generators: small municipal utilities. The Guide helps them navigate the decision-making process involved in selecting economically and environmentally beneficial mitigation options. Burbank Water and Power (BWP) in Los Angeles County serves as a case study to illustrate the decision points necessary for forming a GHG mitigation plan. The specific objectives of the Guide are to:

- Inform utilities about the biophysical aspects of climate change, GHG policy, and utilities' roles in contributing to, and addressing, climate change
- Provide a format for evaluating GHG mitigation options based on key environmental, economic and other criteria
- Describe the menu of available GHG mitigation options and implementation measures
- Describe the steps that a utility should follow to develop its mitigation plan and demonstrate this planning process using BWP as a case study
- Provide a list of key information sources and resources for implementing mitigation options

The Guide describes and evaluates the wide variety of mitigation options that are potentially available to utilities. These include three broad types of opportunities to reduce or avoid GHG emissions: emission reduction, sequestration, or capture and reuse. First, utilities can mitigate GHG emissions through industrial process modifications, transitions from fossil fuel to renewable energy sources, and energy demand efficiency improvements. Second, sequestration involves capture of GHG emissions streams or photosynthetic absorption of CO_2 for long-term removal and storage of the GHGs outside of the atmosphere. Examples of these sequestration approaches include forest and agricultural sequestration, ocean injection and seeding, mineral carbonation and injection into geological formations. Lastly, GHGs can also be captured or absorbed and then processed and/or used in some form. This category includes methane capture from landfills, dairy farms and wastewater treatment facilities (for flaring or electricity generation), and absorption of CO_2 in biomass that is then used in products or to supplant fossil fuel energy sources.

The GHG mitigation planning process for small municipal utilities consists of the six steps presented in this Guide. Steps 1-4 are straightforward for a utility to perform on their own. For the remaining planning steps and subsequent implementation, utilities will benefit from outside expertise.

Step 1: Establish the organization's desire and motivation(s) for mitigating GHGs to facilitate the subsequent steps of setting goals, thinking of project ideas, and evaluating mitigation alternatives. During this process, managers and environmental staff will find it helpful to become knowledgeable about GHG emissions and the climate change problem, the roles of utilities in causing and addressing the problem, other utilities' mitigation activities, and the applicable regulations and policies. This information is provided in the Guide.

Step 2: Create an inventory of the organization's baseline GHG emissions. The Guide recommends using a stringent enough protocol to satisfy future regulations (e.g. from the California Climate Action

Registry or GHG Protocol Initiative); but making a rough emissions estimate to enable the next planning steps if the inventory process is too time-consuming,.

Step 3: Set the organization's goals for GHG mitigation based on the organization's motivations (Step 1), results of the emissions inventory (Step 2) and information in the Guide on GHG mitigation targets set under existing climate change policies and programs and targets set by other organizations. Utilities have a great deal of freedom in setting their targets, so the Guide recommends selecting a goal that has significance for the utility and its stakeholders.

Step 4: Identify relationships with other utilities and businesses for collaborative activities as a means of increasing the available mitigation options. The Guide recommends coordinating with these other organizations early in the planning process.

Step 5: Delineate and categorize a comprehensive list of GHG mitigation project alternatives through structured brainstorming sessions involving managers who are broadly familiar with the organization's facilities and operations, and a consultant that specializes in GHG mitigation for the business community. Participants will need to know the basics of climate change, greenhouse gas mitigation options, potential roles for utilities in solving the problem and the climate change policy setting. They will also need to clearly understand the utility's motivation(s) for mitigating, its major direct and indirect emissions (from Step 2), and its existing energy conservation/efficiency programs that have the potential for expansion. Other useful information (provided in the Guide) includes California's Renewable Portfolio Standards, major sources of GHGs, and examples of mitigation activities by other organizations with similar profiles.

The Guide recommends prioritizing idea-generation by first considering options within the organization to reduce direct emissions; next, examining the potential for reducing the organization's indirect emissions sources; and finally, considering options that are more removed from the organization. The focus should be on high-performing mitigation approaches (e.g. efficiency improvements). This does not mean that other, potentially riskier options should not be included in the list, but it helps utilities avoid overlooking any high-performing possibilities.
Utilities should also:

- consider only options that meet the preliminary screening criteria described in the Guide;
- understand how each alternative abates GHGs and categorize it by mitigation type; and
- describe how alternatives would be implemented (e.g. independent project, collaborative project, investment opportunity, or credit purchase).

Step 6: Evaluate the mitigation alternatives and select one, or a set of, alternatives. In comparing mitigation alternatives, costs will most likely be the primary decision criteria for utilities. However, characteristics of GHG emissions and the climate change problem require incorporation of four key attributes for environmentally successful projects. Inclusion of these attributes also helps to ensure future regulatory acceptance.

(1) The project must have "additionality," meaning that it would not have been done in the absence of the utility's action, and that it results in a surplus of atmospheric GHG reductions beyond what would have occurred in absence of the action.
(2) Quantification, monitoring and verification methods must exist for the type of mitigation for empirically determining the amount of GHG abatement accurately, robustly and cost-effectively.
(3) The project should maximize the degree to which GHGs are permanently removed from or kept out of the atmosphere.

(4) The alternative should not lead to GHG emissions outside of the project.

The Guide provides more project attributes to be considered in the decision process. These include: amount of GHGs mitigated, timing of the mitigation, ancillary effects of the project, regulatory acceptance issues, capacity to leverage existing business relationships, stakeholder preferences, and public perception issues. Utilities will need to decide how important these latter attributes are and weight them accordingly. The evaluation process involves making estimates of costs (e.g. project design, equipment, etc…), project baseline emissions, leakage, permanence, and the amount and timing of mitigation. The Guide includes a matrix format to help utilities organize information and rank alternatives. They should choose the alternatives that meet mitigation targets and perform best.

As fully as possible, the Guide takes the reader through the mitigation planning process for BWP. Potential motivations identified for BWP include the following: to continue to be an environmental leader/innovator; to prepare for future carbon constraints on business; and to generate revenues and reduce costs. BWP is in the process of creating an emissions inventory with the CA Climate Action Registry, but to facilitate the case study in the Guide, BWP's emissions were estimated to be 162,731 metric tons of carbon equivalents per year. We suggest a minimum mitigation target of a 7% reduction from 1990 emissions (as set for the U.S. under the Kyoto Protocol) as an environmentally and socially meaningful target. A few of BWP's existing relationships have been identified for potential collaborations: Southern CA Public Power Authority (SCPPA), L.A. Deparment of Water & Power (LADWP), and Intermountain Power Project (IPP)

Combining the information from the steps mentioned above, six potential mitigation alternatives emerge:

- Switch from less efficient steam boilers to meet peak demand, to BWP's new, efficient gas turbines
- Work with IPP to upgrade its boilers to integrated gasification combined cycle technology
- Invest in methane capture at a California dairy farm
- Collaborate with SCPPA on a wind power project
- Collaborate with IPP or SCPPA for geological sequestration of IPP's emissions
- Purchase credits from Chicago Climate Exchange to offset GHG emissions

A full evaluation of these alternatives (Step 6) is not feasible for the case study. However, a preliminary comparison of the projects' expected attributes suggests that BWP might rank the alternatives similarly to the order in which they are presented above.

1. Introduction

1.1. Problem statement

California's electric power generators are increasingly aware of greenhouse gas (GHG) emissions and their link to global climate change. They recognize the risks to human welfare and the natural environment caused by global warming as well as their role as GHG emitters. Furthermore, utilities are anticipating future limitations of having to operate in a carbon-constrained business environment. They want to prepare for this prospective operational constraint and to act in an environmentally responsible, economically feasible, and politically strategic manner by mitigating their GHG emissions. To make informed decisions, utilities need to be familiar with the characteristics of the climate change problem and the many variables, uncertainties, and potential costs and benefits of specific GHG mitigation options. Applicable information on the steps involved in, and the resources available for, GHG mitigation options has not been synthesized into a format to help utilities make informed choices. Utilities need direction regarding the GHG emission mitigation options that are best suited to their operations.

1.2. Purpose of the guide

The purpose of this document is to provide GHG mitigation guidance for a sub-sector of California's power generators: small municipal utilities. This guide helps these utilities navigate the decision-making process, and outlines the type of information that needs to be obtained, synthesized, and considered for a utility to implement a viable mitigation plan. The specific impetus for this document was a request for guidance on GHG reduction and sequestration options from Burbank Water and Power (BWP), the municipal utility for the city of Burbank in Los Angeles County.

This guide was developed to accomplish the following objectives:

- Inform utilities about the biophysical aspects of climate change, GHG policy, as well as their roles in contributing to and addressing the climate change problem;
- Provide a format for evaluating GHG mitigation options based on key attributes of these approaches and specific decision criteria;
- Describe the menu of available GHG mitigation options and implementation measures.
- Demonstrate the decision points necessary to form a GHG mitigation plan using BWP as a case study; and
- Provide a list of information resources and, where applicable, key resources for implementing GHG mitigation options.

1.3. Structure of the guide

This guide is structured to be read sequentially, taking the reader step-by-step through a progression of learning and decision-making. However, individual sections also function as stand-alone information sources. In some cases, the reader is referred back to previous sections to facilitate understanding.

Chapter 2: Background (p. 8)

Making informed choices for GHG mitigation requires a clear understanding of the scientific and policy background of the climate change issue. Chapter 2 begins with a brief review of key terminology used throughout the guide. (A comprehensive list of terms can be found in the Glossary at the end of this guide.) This is followed by descriptions of BWP and a profile of the audience targeted by this guide. Readers are then introduced to the overarching problem of climate change, the role of elevated atmospheric GHG concentrations in this problem and global warming potentials of various GHGs.

An overview of the utility industry's contribution to GHGs in the atmosphere, the potential roles for small municipal utilities to address the problem, and a brief summary of current GHG mitigation efforts in the U.S is provided. The final section describes existing climate change policy at the international, national, regional and state levels as well as potential future policy directions.

Chapter 3: Assessing Existing Emissions and Setting a Mitigation Goal (p. 39)

Prior to choosing from a menu of mitigation options, utilities need to calculate their net emissions of GHGs and to set a mitigation goal. Chapter 3 introduces methodologies for determining baseline emissions calculations and describes the basic components needed to calculate BWP's emission inventory. This is followed by examples of GHG mitigation goals set by various organizations and specific recommendations for BWP.

Chapter 4: Criteria for Preliminarily Screening GHG Mitigation (p. 44)

To simplify the planning and decision-making process, utilities need to eliminate mitigation approaches that are not feasible or are fundamentally unsuitable for reducing atmospheric GHG levels. Three criteria for screening out unsuitable approaches are described in Chapter 4.

Chapter 5: Criteria for Evaluation of GHG Mitigation (p. 46)

The majority of approaches to mitigating GHGs will not be eliminated from the pool of options using the screening criteria presented in the previous chapter. As a result, additional criteria are necessary for evaluating the merits of different mitigation options. This chapter presents fifteen evaluative criteria that a utility needs to use when assessing GHG mitigation options.

Chapter 6: Mitigation Options (p. 73)

With a clear understanding of the evaluative criteria, utilities are prepared to begin assessing and comparing the different mitigation options. Chapter 6 describes the underlying principles of each mitigation option in detail.

Chapter 7: GHG Mitigation Planning Process (p. 111)

To bring the information presented throughout the guide into a cohesive form, a six-step generic mitigation planning and decision-making process is presented in Chapter 6. This process will guide the decision-maker through key steps necessary for creating an organization's GHG mitigation plan.

Chapter 8: Specific recommendations for Burbank Water and Power (p. 117)

Chapter 8 uses BWP as a case study to present a synthesis of the screening approaches presented in Chapters 4 and 5 in the context of the six-step planning process provided in Chapter 7. Small municipal utilities are steered towards preferred mitigation options with a mitigation priority guide provided at the end of the chapter.

Chapter 9: Resources & Contacts (p. 135)

Chapter 8 describes where to find relevant sources of information on the mitigation options, including examples of GHG mitigation projects that are underway. This chapter discusses who and what parties must be involved for the implementation of a successful GHG mitigation project.

Appendix A is a companion section to Chapter 6. It contains specification sheets for each of the mitigation options in a common format for easy referencing. The specification sheets address the evaluative attributes in Chapter 5 for mitigation options not eliminated using the preliminary screening criteria in Chapter 4 (a discussion of the reasons for eliminating certain mitigation options is contained in Section 8.1.5). A worksheet for comparing mitigation alternatives is also included at the end of the appendix to facilitate Step 6 of the GHG mitigation planning process.

Appendix B contains calculations used throughout the document.

2. Background

2.1. Key concepts used in the guide

This section presents the central concepts used throughout the guide with the objective of ensuring that there is a common understanding underlying the language. A comprehensive set of definitions is in the Glossary.

2.1.1. Mitigation and abatement

Mitigation is an activity undertaken to either reduce releases of GHGs to, or increase removals of GHGs from, the atmosphere (IPCC, 2001c). The term abatement is synonymous with mitigation.

2.1.2. Mitigation option vs. mitigation project

A mitigation option is an overall approach to mitigating the level of GHGs in the atmosphere. For example, reforestation, CO_2 injection into the ocean and transition to renewable energy sources are different mitigation options discussed in this guide. A mitigation project refers to the specific implementation of one of these options.

2.1.3. Types of GHG mitigation options

Three categories of GHG mitigation options exist. Those that involve substituting GHG-producing activities with non-GHG producing activities are reduction approaches. Examples of GHG reductions are improvements to energy efficiency and prevention of deforestation.

Unlike reduction options, all other approaches begin with capturing GHGs that have already been produced (e.g. CO_2 re-absorption by plants during photosynthesis and capture of exhaust wastes from an industrial process). Sequestration is the storage of captured gases in a sink other than the atmosphere (IPCC, 2001c). The scope of sequestration is specifically limited to "(long-term) storage of carbon in forests, soil, the ocean and other carbon sinks" (Pew Center, n.d.).

Under the capture and use category, atmospheric GHGs are captured and then incorporated into products and energy sources that substitute for GHG-producing activities. For example, a crop such as corn might be grown to produce ethanol, which then replaces the use of fossil fuels.

2.1.4. Baseline definitions

The term baseline is used in two ways referring to: 1) an emission baseline of a GHG emitting entity and 2) a project baseline of a GHG mitigation project.

An **emissions baseline** is a reference against which to measure GHG emissions performance for a project over time. Usually this reference level is the utility's emissions in a selected base year. (CA H&S Code, §42801.1(b), 2004).

A **project baseline** is the predicted amount of GHG emissions that would have occurred in the absence of a proposed mitigation project. This baseline serves as a reference level against which the mitigation benefits of a project are measured (UNFCCC, 29 October – 10 November 2001).

2.1.5. Offsets

Offsets are the metric tons of carbon equivalents (MTCE) generated through GHG mitigation. Unlike direct reductions of a utility's own GHG emissions, offsets are generated through mitigation projects that counteract the utility's GHG emissions. The number of offsets created from a mitigation project is calculated with respect to the project baseline (see Section 2.1.4).

2.1.6. Leakage

In GHG mitigation, **leakage** is defined "as the unanticipated decrease or increase in GHG benefits outside of the project's accounting boundary (the boundary defined for the purposes of estimating the project's net GHG impact) as a result of project activities (IPCC, 2000)."

This definition differs from that of **emissions leakage** which refer to fugitive emissions or the unwanted discharge of fluids or gases from equipment.

2.2. Target audience for the guide

Small municipal utilities in California are the target audience for this guide. The primary objective is to address the specific needs of BWP. However, this guide also applies to other utilities that resemble BWP in terms of customer base, power generation and sales, or organizations that wish to become informed about, and get involved in, GHG mitigation.

The characteristics of the target audience for this guide, such as BWP, include:

- Small staff size, and therefore limited availability of internal resources for research of GHG mitigation options;
- Low levels of on-site power generation, thus having low levels of direct GHG liability;
- Few land-holdings with limited capacity for engaging in large, land-intensive mitigation projects; and
- Minority shares of large power projects that could potentially contribute to the organization's indirect GHG liability.

Municipal utilities in California that fit with this profile are identified in Table 2.2.1. The last column illustrates the expected bulk of GHG emissions due to fossil fuel-based power supply activities.

Table 2.2.1. California municipal utilities with profiles similar to BWP.
(Values in table are derived from SCPPA, 2004 & n.d.)

Utility	Number of customers[a]	Power provided annually[b] (million kWh)	Amount (and type*) of generation[c] (in million kWh)	Percent of total power provided that is fossil fuel generated
Anaheim Public Utilities Dept.	109,000	3,522	119 (N/A)	>65%
Azusa Light & Water Dept.	15,000	238	0	>60%
Banning Electric Dept.	10,000	136	0	N/A
Burbank Water and Power	**51,000**	**1,809**	**171 (Natural gas)**	**>80%**
Colton Public Utilities	18,000	292	0	>90%
Glendale Public Service Dept.	83,000	1,489	167 (Natural gas)	>45%
Pasadena Water and Power Dept.	58,000	1,613	291 (N/A)	~60%
Riverside Utilities Dept.	95,000	2,603	250 (N/A)	~65%

*N/A indicates that the information is not available.
[a] = residential, industrial, commercial
[b] = generated and purchased electricity
[c] = annual onsite electricity generation

2.2.1. Overview of BWP operations

In 2004, BWP supplied approximately 1800 million kWh of electricity to over 50,000 customers. With only 10% of this electricity generated on-site (via natural gas and hydroelectric production), BWP has a low level of direct GHG emissions relative to other utilities in the power production sector. However, BWP's indirect emissions potential is much higher than their direct emissions due to purchases of the remainder of its supplied power through a mixture of agreements with public and private generation projects. Approximately half of this external supply is coal-generated with another 20-25% coming from other fossil fuel-based generation (Burbank Water and Power, 2003). At least 20% of the off-site power comes from non-GHG-intensive production – hydroelectric, nuclear and renewable energy forms. Future GHG emissions due to on-site generation are expected to rise from current levels. BWP management anticipates a continued increase in power demand of 2.5-5% per year due to population growth. To address this growth, BWP is currently building a new 320 MegaWatts (MW) combined cycle facility on-site to supply Burbank and surrounding cities (CEC, 2003a). The work on this facility is anticipated to be complete by the summer of 2005.

2.2.2. Target readers within the organization

Two types of readers are expected to benefit from this guidance document. It is primarily intended to aid a staff member who has been given the task of developing recommendations for upper management on ways to reduce the utility's GHG liability. However, upper managers who wish to become familiar with the specific issues and complexities of GHG mitigations should also find this guide useful.

2.3. Elevated GHGs in the atmosphere

Translating the predicted rise of GHG levels in the atmosphere into environmental consequences is the focus of a broad range of climate modeling research. Although the specific characteristics of climate change impacts are still being investigated, the role of anthropogenic emissions of GHGs in changing global temperatures is clear. This section discusses the global carbon cycle, the basic scientific processes by which enhanced atmospheric GHGs concentrations lead to warming, the relative roles of different gases in these processes, and reviews the problem of climate change impacts.

2.3.1. The global carbon cycle

With the recent dramatic alteration of the atmospheric carbon budget, interest in understanding the global carbon cycle has intensified over the last few decades. The cycling of carbon between the four main carbon reservoirs is a natural process (Figure 2.3.1). The four reservoirs are:

1. the atmosphere,
2. the biosphere (terrestrial and marine biota),
3. the hydrosphere (ocean, rivers, lakes), and
4. the lithosphere (soil, rocks, and land surface),.

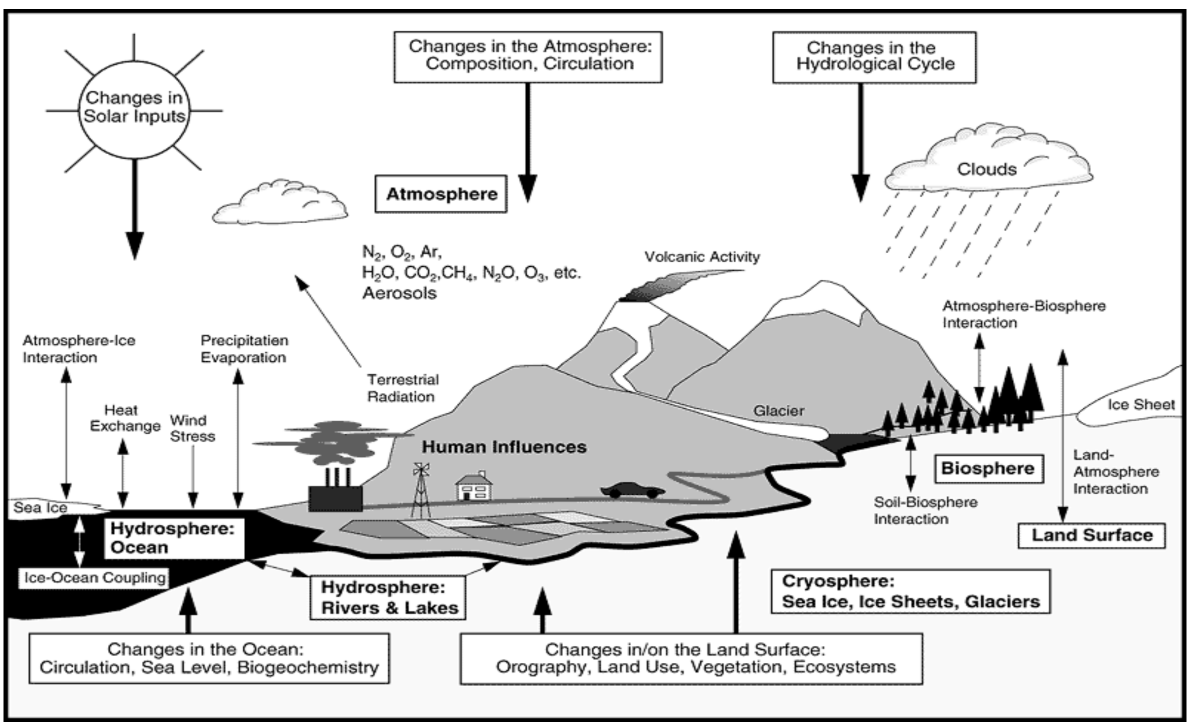


Figure 2.3.1. Schematic of global climate system processes and interactions.
(Source: IPCC, 2001b)

Carbon (C), in the form of CO_2, is constantly exchanged among these carbon pools with the largest exchanges occurring between the atmosphere and terrestrial biota and between the atmosphere and sea surface (IPCC, 2001b). Carbon exchange is facilitated by the natural processes of photosynthesis (plant uptake of CO_2), respiration (the release of energy and CO_2 from organic substances), dissolution, and carbonate precipitation (IPCC, 1994; Grace, 2001).

A carbon pool is defined as a source or sink, depending on whether it emits CO_2 into the atmosphere or absorbs it from the atmosphere. Photosynthesizing vegetation takes up CO_2 and sequesters it as biomass carbon in the terrestrial carbon pool. CO_2 enters the soil carbon pool when dead biomass decomposes. In the ocean, CO_2 is naturally taken up during the exchange of CO_2 gas at the ocean surface-atmosphere interface or by photosynthetic algae. When algae (and other marine inhabitants) die, they sink. Under the right conditions, a large proportion of that sinking biomass stays sequestered in the deep ocean (IPCC, 2001b; Grace, 2001).

Soil, vegetation and the ocean are considered potential sinks of CO_2 because of the large quantities of CO_2 currently sequestered in these pools and their capacities to continue taking up CO_2. Forests and soils currently contain about 2,000 Gigatons (Gt) C and take up 0.5 Gt C per year (Malhi et al., 2002). Global oceans contain 38,000 Gt C, and sequester an additional 1.7 ± 0.5 Gt C/yr. However, seawater below the thermocline (a sharp temperature gradient found in the ocean) is thought to be highly unsaturated with CO_2, yielding a potential for the deep oceans to sequester an additional 1,400-20,000 Gt C (Yamasaki et al., 2003). The potential extent of the ocean sink is what makes it a tantalizing mitigation option. In contrast to the other carbon pools, the atmospheric reservoir contains 760 Gt C. Anthropogenic CO_2 emissions only add an additional 3-4% (approximately 6.3 Gt C) of the total of naturally cycling carbon to the atmosphere (PIER, 2002). However, this addition is enough to alter atmospheric CO_2 concentrations to the point of causing changes to the Earth's climate.

Conversion factors for carbon units discussed throughout this report are presented in the box below.

Carbon Units and Conversion Factors

- 1 Gigaton (Gt) = 1 Petagram (Pg) = 1 million Gigagrams (Gg) = 10^{15} grams = 1 billion (10^9) metric tons
- 1 Teragram (Tg) = 10^{12} grams = 1 million (10^6) metric tons
- 1 unit CO_2 = 0.l2727 or 12/44 units C
- 1 unit carbon (C) = 3.6667 or 44/12 units carbon dioxide (CO_2)
- 1 Gigaton C = 3.66 Gt of CO_2

For converting values with Global Warming Potential (GWP)- weighted emissions, (sometimes reported in Tg of gas) to Tg of CO_2 or CO_2 equivalent, the following equations can be used:

$$Tg\ CO_2\ equivalent = Tg\ of\ \ gas * \frac{1\ gigaton}{1000\ teragrams} * GWP$$

$$Tg\ carbon\ equivalent = Tg\ CO_2\ equivalent * \frac{12g\ C}{44g\ CO_2}$$

(Source: DOE, 2004d; EPA, n.d., http://www.epa.gov/ngs/units.html)

2.3.2. *The greenhouse effect*

The greenhouse effect is a natural process that aids in heating the Earth's surface and atmosphere. Incoming solar radiation is absorbed by the Earth's surface and emitted as infrared radiation (heat) which can either be absorbed by the atmosphere or escape into space. This process is illustrated in Figure 2.3.2 Radiation trapped by the atmosphere is reflected in all directions, including back to the Earth causing the surface warming. Without this natural greenhouse effect, the average Earth surface temperature would be a chilly -19 °C (2.2 °F) rather than the warm 14 °C (57.2 °F) that it is now. (Dobson, 2002; IPCC, 2001b).

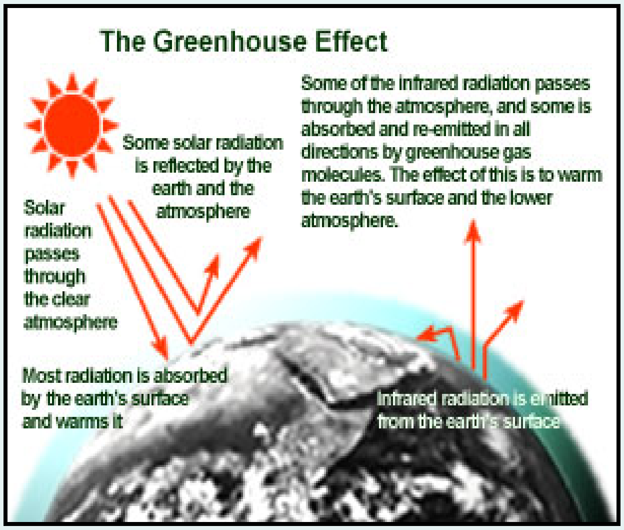


Figure 2.3.2. GHGs contribute to warming of the Earth's surface and lower atmosphere by absorbing and retransmitting energy toward the Earth. (Source: EPA, n.d., "The Greenhouse Effect")

The problem of climate change and global warming occurs when GHGs accumulate in the atmosphere, increasing the amount of radiation that is absorbed by the atmosphere and re-emitted back to the Earth's surface. The "enhanced" greenhouse effect is caused by anthropogenically-produced GHGs, such as CO_2 generation from fossil fuel combustion, above and beyond the effect caused by natural concentrations of GHGs. Changes in the energy balance of the earth-atmosphere system is also called radiative forcing (IPCC, 2001b).

2.3.3. *GHGs and GWP*

Only certain molecules in the atmosphere can absorb and emit infrared radiation. For the most part, gases like nitrogen and oxygen which comprise 78% and 21%, respectively, of the Earth's atmosphere are relatively non-reactive. A minute fraction of gases, the GHGs, are responsible for trapping heat in the atmosphere (IPCC, 1994).

Greenhouse gases are both naturally-occurring and man made, though anthropogenic activities have increased the levels of the naturally-occurring gases. The GHGs are:

- water vapor
- carbon dioxide (CO_2)
- methane (CH_4)
- nitrous oxide (N_2O)
- ozone (O_3)
- hydrofluorocarbons (HFCs)
- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF_6)

The last three gases, HFCs, PFCs, and SF_6, are not naturally occurring (EPA, 2002c).
To compare the radiative forcing capacity of different gases, an index termed the global warming potential (GWP) is calculated for each gas. For example, methane[1] has a GWP of 23 which means that it is 23 times more effective at trapping heat than CO_2.

[1] In the IPCC's Third Assessment Report (TAR), the GWP of methane was re-evaluated and changed from 21 to 23. However, many EPA documents have not yet incorporated this change. As a result, this guide uses the previous value of 21 for all calculations and references to methane GWP.

GWP is calculated based on the amount of time a gas remains in the atmosphere and its relative effectiveness in absorbing infrared radiation. The IPCC computes greenhouse gas GWPs for 20, 100, and 500 year time horizons (listed in Table 2.3.3). GWPs vary depending on the time horizon computed due to the atmospheric lifetime of the GHG. Carbon dioxide is used as the reference gas against which other gases are compared (IPCC 1994; EPA, 2002c). The two GHGs of primary concern are carbon dioxide (CO_2) and methane (CH_4) because most GHG-producing anthropogenic activities result in the emission of one of these gases.

Table 2.3.3 Global warming potentials (GWPs) relative to CO_2 and their abundance for selected greenhouse gases. (Information for this table was compiled from IPCC, 2001b, Table 6.7 & Table 4.1a.)

Gas (Formula)	Atmospheric Lifetime (years)	Abundance 1998 (ppt)[a]	GWP 20 yr time horizon	GWP 100 yr time horizon[b]	GWP 500 yr time horizon
Carbon dioxide (CO_2)	5-200	366 (ppm)	1	1	1
Methane (CH_4)	12	1745	62	23	7
Nitrous oxide (N_2O)	114	314	275	296	156
CF_4	50000	80	3900	5700	8900
C_2F_6	10000	3.0	-	11900	-
Sulfur hexafluoride (SF_6)	3200	4.2	15100	22000	32400
HFC-23 (CHF_3)	260	14	9400	12000	10000
HFC-134a (CF_3CH_2F)	13.8	7.5	3300	1300	400
HFC-152a (CH_3CHF_2)	1.4	0.5	410	120	37

[a] (ppt) = parts per trillion. CO_2 is present at parts per million concentrations.
[b] 100 yr time horizon = the time horizon most commonly used when talking about GWP.

2.3.4. The problem of climate change and global warming

According to the Intergovernmental Panel on Climate Change (IPCC), average global temperatures increased 0.6 ± 0.2°C over the last century (IPCC, 1994). In 2004, an international science panel released the Arctic Climate Impact Assessment which documented an even faster rate of increase in Arctic temperatures – at least twice as much as the rest of the world – and the accompanying consequences. Arctic snow cover has declined by 10% over the last 30 years and is predicted to decline by another 10-20% by 2070.

Throughout the Arctic, glaciers are melting and summer sea-ice cover is declining, leading to a rise in sea level (10-20 cm in the past century). Reduced salinity and density have been observed in the North Atlantic due to the influx of freshwater from melting glaciers, which is predicted to change ocean circulation and regional climate patterns (ACIA, 2004).

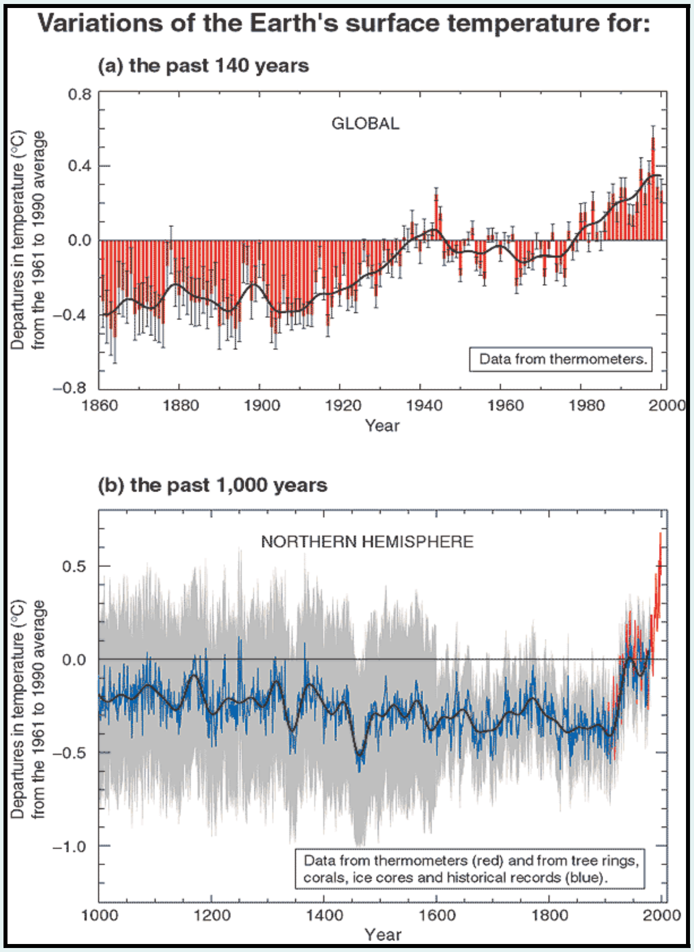
These effects seem removed from the issues facing California, – particularly from the perspective of a municipal utility that is serving the needs of a regional or local customer base. However, regional climate modeling of impacts to California under the expected atmospheric GHG concentrations in 2100 suggests that, among other effects, snow pack in the Sierra Nevada will decline by 30-70%, and that areas such as Los Angeles can expect to experience more heat waves and extreme heat events during summers (Hayhoe et al., 2004). These outcomes are not certain, but they are based on predictions from highly refined climate models using comprehensive data sets.

A growing body of evidence points to anthropogenic activity as the primary driving force for the climate impacts described above. Atmospheric carbon dioxide levels have increased dramatically since the 1800s. Ice cores show that pre-industrial levels of atmospheric CO_2 over the last 1000 years have fluctuated around 280 ± 10 ppm.

However, within the last century and a half, the rate of increase of atmospheric CO_2 has been steadily increasing: from 280 ppm in 1850 to 315 ppm in 1957, and now due to a large increase (of 65 ppm) within the past 50 years, to a current CO_2 concentration of 374 ppm.

The recent jump in CO_2 concentration corresponds to increases in Earth's surface temperature that are shown in Figure 2.3.4. Scientific research points to the anthropogenic activities of fossil fuel combustion and land use change as the cause of this jump (IPCC, 1995). The IPCC predicts that at our present rates of emission, atmospheric CO_2 concentration will climb to 670-970 ppm by 2100 resulting in a 6°C increase of global temperatures. (IPCC, 2001b).

Figure 2.3.4. Historical records of variations of the Earth's surface temperature show a rapid increase in temperature over a short, 60 year period.



Source: IPCC, 2001a

2.4. Sources of GHG emissions

2.4.1. Global emissions of GHGs

Global anthropogenic GHG emissions average 7-8 Gt C/year (IPCC, 2001a). The largest component of anthropogenic GHG emissions is CO_2 emitted by energy-related activities.In 2000, an estimated 6611 million metric tons of carbon (~6.6 Gt) was emitted globally. Twenty five percent of total global emissions came from the U.S. with an estimated 1529 million metric tons of C (1.5 Gt C). This is approximately twice the amount of the world's second largest emitter, China, which emitted a total of 762 million metric tons of Carbon equivalent (MMTCE) in 2000. Figure 2.4 ranks the top 20 CO_2 emitting countries by percentage of world emissions. The U.S. is ranked first, with China and Russia coming in a distant second and third (Marland et al., 2003).

Top 20 CO_2 Emitting Countries (2000)

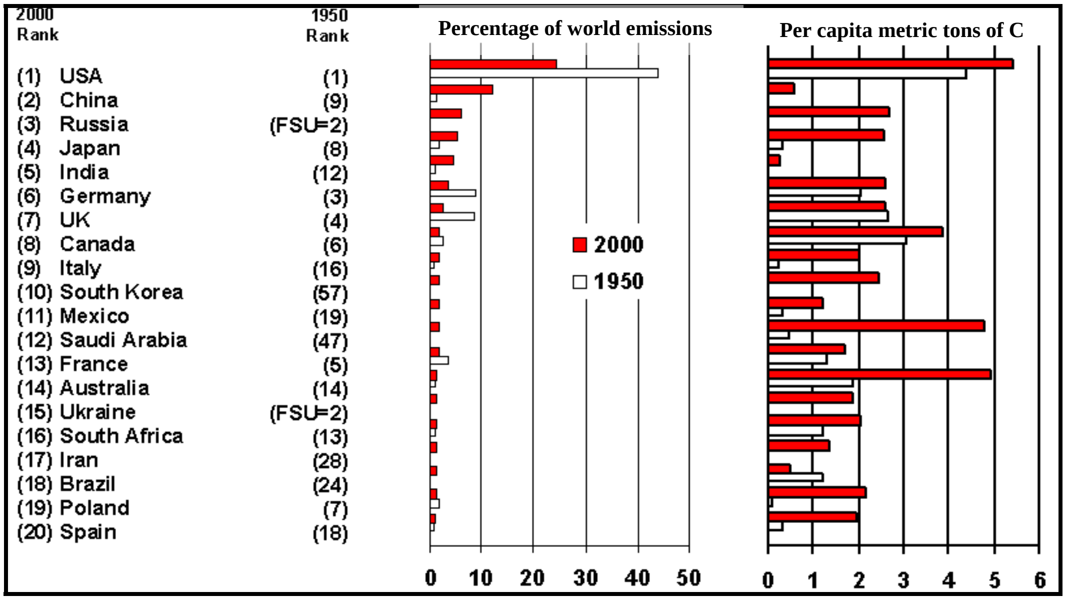


Figure 2.4.1. A comparison of the top 20 CO_2 emitting countries in 2000.
(Source: Marland, et al., 2003)

2.4.2. U.S. National emissions of GHGs

The major GHG emitters can be roughly broken down into five (sometimes six) economic sectors – residential, commercial, industrial, electricity generation and transportation (a sixth sector, agriculture, is sometimes separated out). The electricity generation and transportation sectors are responsible for more than 60% of all U.S. emissions (See Figure 2.4.2.a) (DOE, 2004d).

GHG emissions for 2003 are broken up as follows: electricity generation (33%), transportation (27%), industrial (19%), residential (6%), commercial (7%), and agriculture (7%). The transportation sector accounts for over one quarter of all GHG emissions. About half of these emissions are from personal automobiles, such as cars and sport

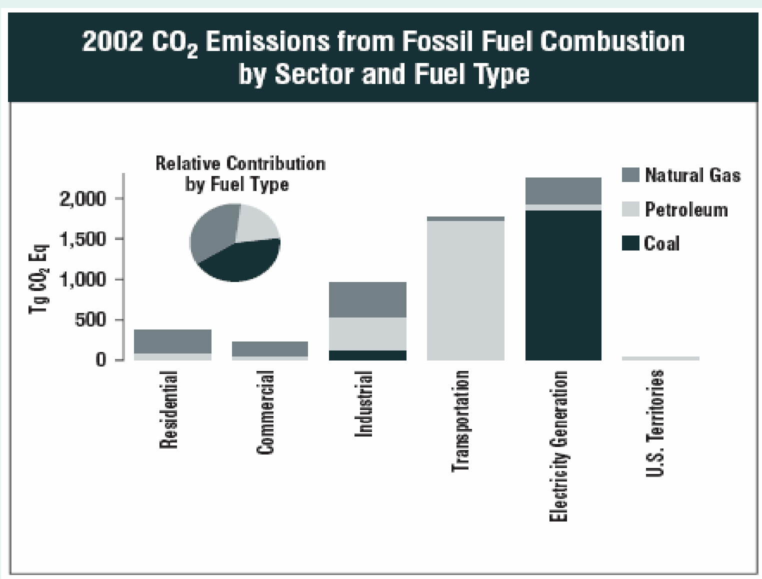
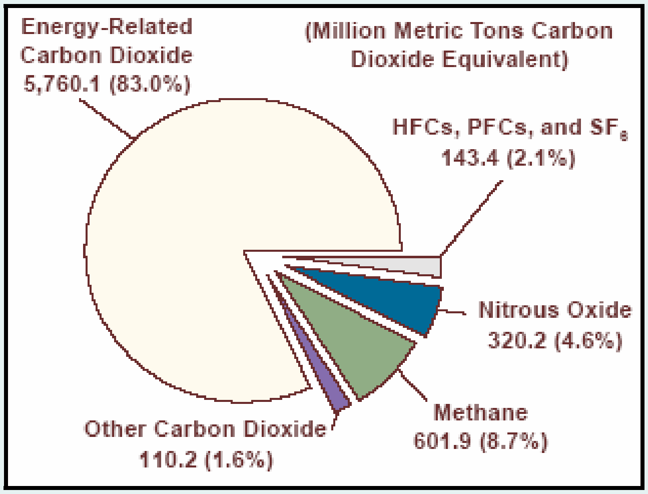


Figure 2.4.2.a. Emissions are reported in teragrams of CO2 equivalent (1 teragram = 1 million MT). (Source: EPA, 2004a)

utility vehicles. The remainder of emissions are from diesel trucks, and airplanes powered by jet fuel (EPA, 2004a). In the industrial sector, the primary source of CO_2 emissions is cement production with 90% of total industrial emissions created during the calcination of limestone

Figure 2.4.2.b. 2003 U.S. greenhouse gas emissions. CO_2 comprises over 80% of total U.S. GHG emissions. (Source: DOE, 2004d)



Carbon dioxide comprises over 80% of total GHG emissions in the U.S. (Figure 2.4.2.b) (DOE, 2004d). Unlike CO_2, which is emitted primarily from energy-related activities, methane (CH_4) and nitrous oxide (N_2O) come from a variety of sources, including waste streams, fertilizer use, fugitive emissions from chemical processes, and fossil fuel production, transmission, and combustion. More than 70% of CH_4 emissions are from landfills, natural gas systems (natural gas is about 98% methane), and enteric fermentation from animal digestion (DOE, 2004d). About 70% of N_2O emissions are from agricultural soil management activities – such as fertilizer and manure application (DOE, 2004d).

2.4.3. California emissions of GHGs

In California, fossil fuel consumption of natural gas for electric power and motor gasoline for the transportation sector dominates all other consumptive activities. The transportation sector is responsible for 58% of CO_2 emissions, while the electric power sector only makes up 16% of California's emissions (Figure 2.4.3). The electric power sector's relatively smaller impact on CO_2 emissions can be attributed to several factors: (1) Natural gas combustion produces less CO_2 than other fossil fuels; (2) California electricity comes from a mix of hydro, nuclear, and out of state coal power; (3) Electric utilities are already actively participating in voluntary GHG emissions reductions or offset activities; and (4) a large amount (over 20%) of power is imported from out-of-

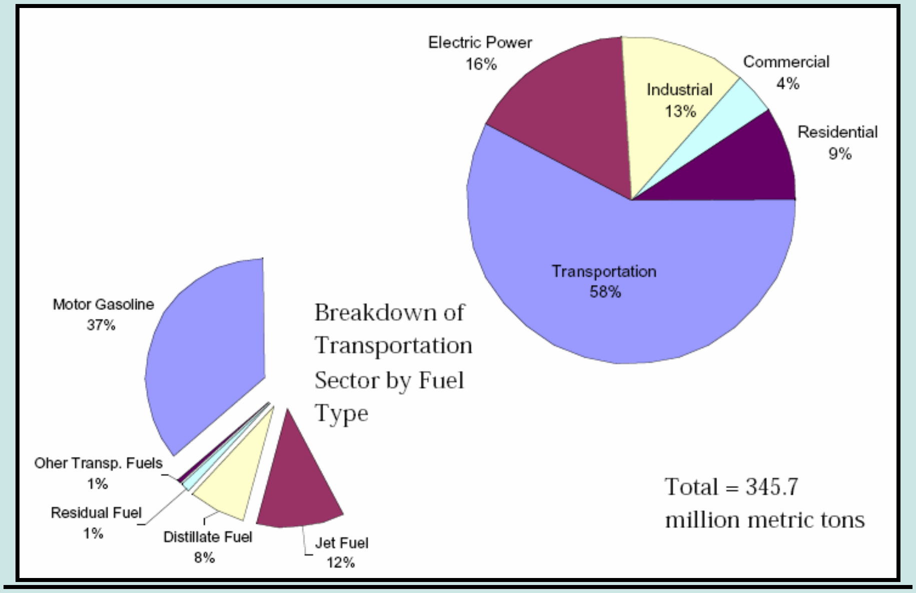


Figure 2.4.3. California emissions by sector. (Source: PIER, 2002)

state coal-fired power plants (PIER, 2002). Due to this last factor, however, the reported CO_2 emissions from California's electric power sector are a bit misleading.

Similar to national emissions, landfill waste and agriculture are the primary sources of methane and nitrous oxide emissions in California, while carbon dioxide comes primarily from energy-related activities. In 1990, California GHG emissions totaled 356.3 $MMTCO_2$ (million metric tons of carbon dioxide equivalents) or 97.2 MMTCE (million metric tons of carbon equivalents). Future GHG emissions in California are expected to increase 20% from 1990 levels (PIER, 2002).

2.5. Utilities' role(s) in addressing the problem

California's municipal utilities have multiple opportunities to address climate change.
A variety of institutions, including the Pew Center on Global Climate Change, The Union of Concerned Scientists, and the Tellus Institute findings on behalf of the West Coast Governors' Global Warming Initiative, have conducted research and policy analyses on this issue and suggest specific actions and roles for California's municipal utilities (Pew Center, 2001; UCS, 2004b; Bailie et al., 2004; West Coast Governors' Global Warming Initiative, 2004).
Certain opportunities for addressing climate change are nonspecific to utilities:

- Tracking and reporting of GHG emissions
- Improved energy efficiency and conservation efforts
- Improved vehicle efficiency and alternative transportation systems
- Updated building and appliance efficiency standards

Other recommended actions represent opportunities that are more specific to power generators and providers:

- Increased power plant efficiency
- Transitions to renewable energy source for power generation

Readers should note that the vast majority of organizations focus on efficiency improvements and, to a lesser extent, renewable energy generation (to replace traditional fossil fuel energy sources) as a means of cost-effectively reducing their GHG emission liability. Based on these general, sector-wide recommendations, these emissions reductions approaches should form the core of a utility's GHG mitigation plan.

In contrast, GHG capture/use and sequestration projects are not among the list of priority actions for the utilities sector. This reflects, in part, the current status of GHG mitigation technology development. Sequestration and capture/use approaches are not as easily quantified as many emissions reductions methods. Furthermore, mitigation options that involve re-capturing GHGs that have *already* been emitted to the atmosphere are inherently more complex than approaches that prevent emissions. This complexity exists both in terms of technology requirements as well as the availability of policy designed to accommodate the unique characteristics of these projects. Despite these existing hurdles, sequestration and capture/use approaches should not be eliminated from the pool of options, rather they need to be a part of the "mixture" of GHG mitigation solutions (ED, 2003; Hayes & Gertler, 2002).

2.5.1. Mitigation options

With the inclusion of all three mitigation categories – emissions reductions, sequestration and capture/use – the menu of mitigation options is quite diverse. The types of mitigation options that fall within these three categories are briefly presented in Table 2.5.1. The options are described in detail in Chapter 6. This guide evaluates each of these options (Appendix A) generally, in terms of efficacy of the underlying scientific theory for each option as well as economic, environmental, methodological, perception and future considerations.

Table 2.5.1. The categories of mitigation options.

Reductions	Sequestration	Capture and Use
▪ Industrial process modifications ▪ Renewable energy transitions ▪ Demand side efficiency improvement	▪ Forest sequestration ▪ Agricultural sequestration ▪ Geological sequestration ▪ Ocean sequestration ▪ Mineral carbonation	▪ Methane capture ▪ Biomass to energy ▪ Biomass to product 

2.5.2. Strategies for implementing mitigation actions

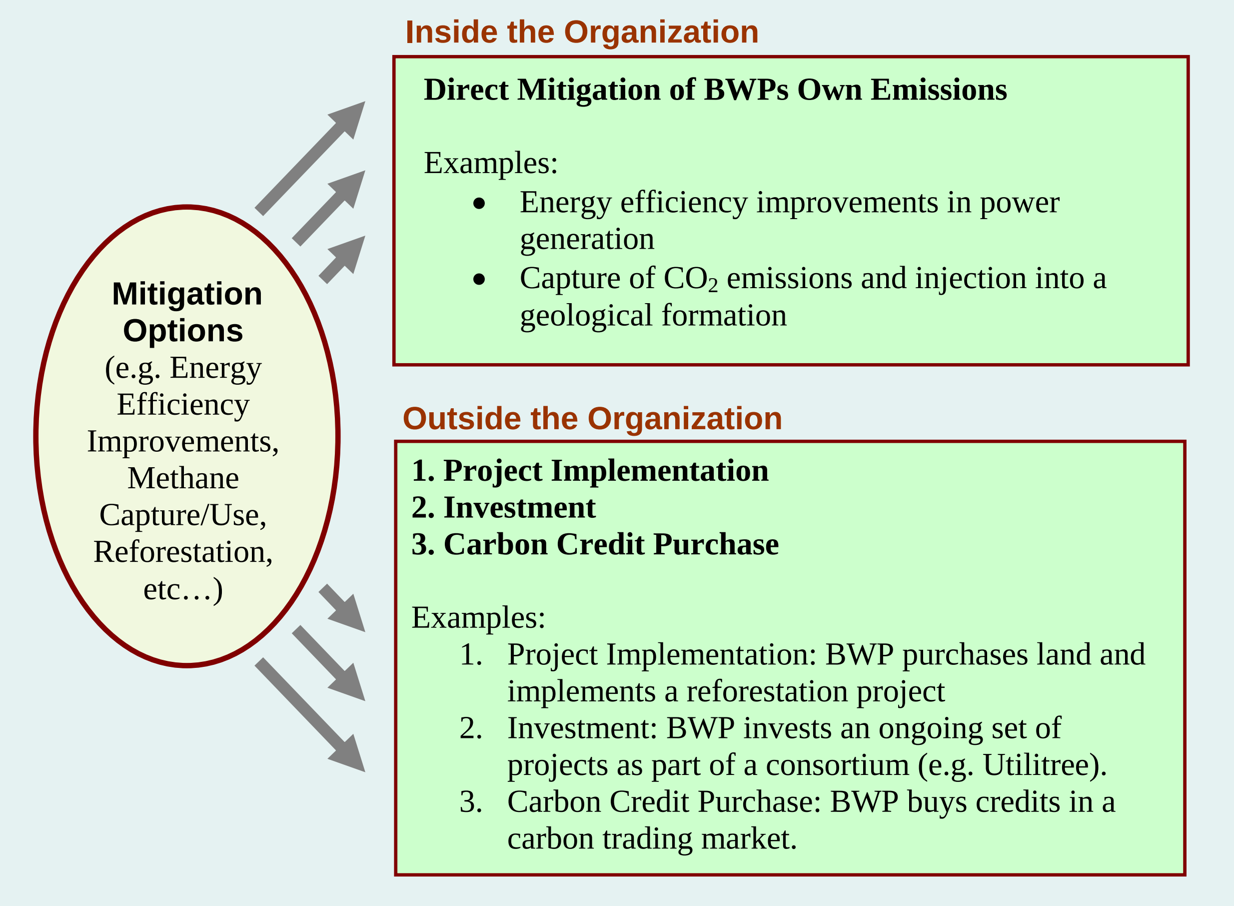
Utilities have several choices for how they implement the mitigation options listed in Table 2.5.1. Depending on what they choose to do, utilities might be 'removed' from the mitigation actions (i.e. are not directly implementing them). Nevertheless, they need a clear understanding of the details and merits of all the available options to facilitate good decision-making.

Strategies for implementation fall under two, broad categories as presented in Figure 2.5.2:

- **Within the organization**, a GHG emitter can take actions to mitigate its own, direct emissions.

- **Outside of the organization**, potential mitigation actions by a GHG emitter fall under three sub-categories: (1) direct project implementation. (2) investments as a partner, or contributor, to a larger mitigation action (or set of actions), and (3) carbon credit purchases.

Figure 2.5.2. Implementation strategies.



1. *Direct project implementation:*
   A small municipal utility might choose to implement its own GHG mitigation project for certain types of mitigation options. In this case, the utility is the initiator, major funder, planner and manager of the project – it retains majority control and ownership of the project.

   Small municipal utilities should not rule out the possibility of implementing their own projects outside of their organizational boundaries, but they should recognize that this option is less feasible than the other two courses of action discussed below. Significant economies of scale that are associated with most mitigation options prevent independent project implementation on the part of an organization that only needs or wants to offset a relatively small amount of GHG emissions. Therefore, a utility will want to keep the following issues under consideration when implementing a project independently.

Small municipal utilities should not rule out the possibility of implementing their own projects outside of their organizational boundaries, but they should recognize that this option is less feasible than the other two courses of action discussed below. Significant economies of scale that are associated with most mitigation options prevent independent project implementation on the part of an organization that only needs or wants to offset a relatively small amount of GHG

emissions. Therefore, a utility will want to keep the following issues under consideration when implementing a project independently.

- The minimum required investment in an independent project could exceed a small municipal utility's resources allocated to GHG mitigation.

- California's municipal utilities that choose to act now to mitigate GHGs (in preparation for future carbon constraints) do not have the security of a well-defined regulatory landscape.

- With a single-project approach (as opposed to investing in multiple GHG mitigation projects), they accept a greater risk of losing all offsets benefits if future policy and regulations are unfavorable.

- Another consideration is that the mitigation options presented in Table 2.5.1 vary in terms of their demonstrated performance. With future technology and policy mechanisms, the relative favorability of the approaches may change. Depending on a utility's motivation for mitigating GHGs, it may or may not want to be an early-adopter of a certain approach.

2. *Investments in mitigation actions:*
   Another alternative for participation in GHG mitigation is through investments in mitigation projects (or set of projects) that are managed by another organization(s). There are a variety of ways to design specific investment agreements, such as partnering with other organizations on a single project, or participating in a consortium that is pursuing a portfolio of mitigation actions. A manifestation of this logistical approach could be an agreement similar to some of the municipal utilities' power projects (e.g. the San Juan Unit 3) that have been arranged by the Southern California Public Power Authority (SCPPA, 2004). A comparable management structure and financing approach could be applied to a project that has a primary function of producing GHG offsets instead of electricity.

   This investment alternative is more feasible than the independent, direct project implementation. By pooling their collective resources and mitigation objectives, the participating organizations can take advantage of economies of scale. At the same time, this facilitates diversification of a small municipal utility's GHG mitigation portfolio by enabling it to spread investments among a variety of approaches and defusing the risk of any one project failing.

3. *Purchase of carbon credits:*
   The third option is the purchase of GHG offsets – credits representing tons of carbon removed from the atmosphere. This is distinguished from an investment alternative because the utility would be further removed from the actual mitigation action by an intermediary trading organization that consolidates offsets generated by many mitigation projects. This organization holds responsibility for guaranteeing the validity of the offsets that it sells. In the U.S., only one trading market for carbon credits currently exists, the Chicago Climate Exchange, but a market for New England states (that might allow outside participation) is on the horizon (Pew Center, 2004).

   Purchase of the credits could provide a straightforward approach for conveying the organization's commitment of addressing climate change to its stakeholders. It remains uncertain, though, whether these credits will be recognized under future state, regional or national legislation. Relying solely upon this mechanism to prepare for future carbon-constraints instead of implementing and/or investing in projects could leave utilities ill-equipped to comply with regulations that preclude the use of credits purchased from specific trading markets.

2.5.3. *Outcomes of mitigation actions*

It is important to distinguish between the potential outcomes of a successful GHG mitigation action. In all cases, **the outcome should be a net reduction of GHGs in the atmosphere as compared to taking no action**. Most often, actions will result in a direct subtraction from a utility's baseline emissions (see discussion in Chapter 3). However, in some instances, a utility might decide to sell the rights to the mitigated GHG (i.e. act as a supplier of carbon credits). This might occur due to direct project implementation or investment actions that mitigate more tons of GHGs than a utility seeks to, or has to achieve under future regulations. This would provide an opportunity to supply credits by encouraging additional participation from investors or through sale of the excess offsets to a credit aggregator that participates in a trading market, such as the Chicago Climate Exchange.

Depending on the mitigation action, the utility might also derive a monetary or ancillary benefit. Examples of this include: cost savings from power generation efficiency improvements; sale of electricity from a landfill methane capture and generation project; sale of an agriculture-derived product (e.g. lumber); and sale of unused water from an agricultural project for power generation.

The Chicago Climate Exchange

The prospect of a carbon constrained business world has prompted the development of the **Chicago Climate Exchange (CCX)**, a self-regulating, voluntary, and legally binding exchange program of tradable carbon that intends to incentivize the pursuit of GHG emission reductions (CCX, 2004).

With an active membership base of approximately 50 organizations from the business, public, and non-governmental sectors, CCX has set out to demonstrate that a market-based program is the means to advance the information and technology of GHG emissions and reductions; create economic signals that reduce uncertainty and stabilize the value of carbon; and provide a platform where vested interests can hone their own knowledge base, enhance their reputation, and develop a competitive advantage in an upcoming market (CCX, 2004). R

Recognized reduction strategies are landfill and agricultural methane capture and use and forest and agricultural soil sequestration. These strategies are used by members to meet their reduction goals with additional reductions capable of being purchased by other members unable to reduce within their own organization.

2.5.4. *Present mitigation activities by utilities*

Electric power utilities account for about 40% of all GHG emissions in the U.S. Many utilities already have experience with activities that reduce their CO_2 emissions, such as switching inputs from coal to natural gas. This has been done to reduce criteria pollutants, but it has also become a recognized way to decrease GHG emissions. This section describes some of these ongoing mitigation activities by utilities and other businesses. The following are overarching points about the current mitigation activities:

- Utilities and other businesses have already begun implementing GHG mitigation measures on a voluntary basis;
- These efforts encompass a variety of mitigation approaches, including non-traditional sequestration projects; and
- In terms of total GHG mitigation, however, the largest benefits (by far) are created through efficiency improvements in electricity generation.

Since GHGs are not regulated in the U.S., all mitigation efforts by electric utilities to date have been voluntary. The Climate Challenge program, begun in 1994, has been the main source of information relating to industry action towards GHG mitigation. In 2002, a total of 228 organizations completed 2,027 projects related to the reduction, avoidance, or sequestration of GHGs. These projects led to direct reductions of 72 MMTCE, indirect reductions of 22 MMTCE, sequestration of 2 MMTCE, and other reductions of 5 MMTCE. This was a considerable increase from the program's initial year, where 108 organizations completed 634 projects. This led to 20 MMTCE reductions, most of them direct reductions (DOE, 2004d).

As shown below in Figure 2.5.4.a., efficiency improvements in electricity generation, transmission, and distribution were the most numerous projects, totaling 456 in 2002. The number of projects involving waste treatment and disposal totaled 452. There were also 426 carbon sequestration projects, and 412 energy-efficiency projects (DOE, 2004d).

These project numbers do not reflect the proportional quantities of GHG mitigation associated with each category. As shown above, sequestration projects accounted for about 21% of all projects. However, sequestration accounted for only about 3% (2 MMTCE) of total GHG mitigation. The amount of reductions per sequestration project was about 5,000 tons of C (Figure 2.5.4.b). Projects involving electric power, energy end use and ozone depleting substances (ODSs) achieved at least six times the amount of reductions per project as sequestration.

Figure 2.5.4.a. Number of GHG mitigation projects reported to DOE in 2002.
(Source: DOE, January 2004c)

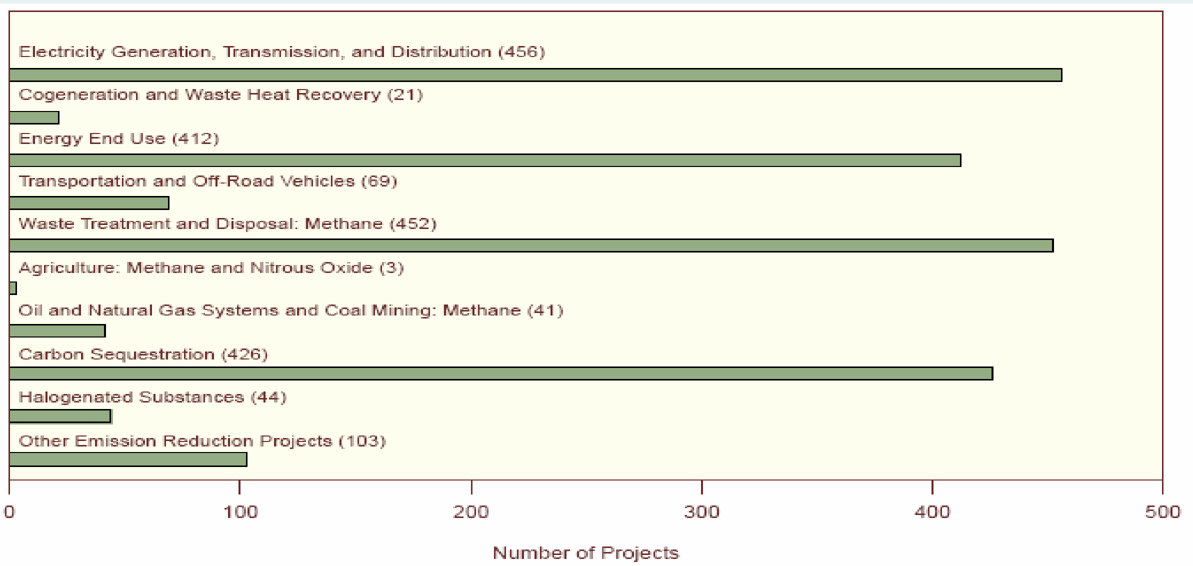
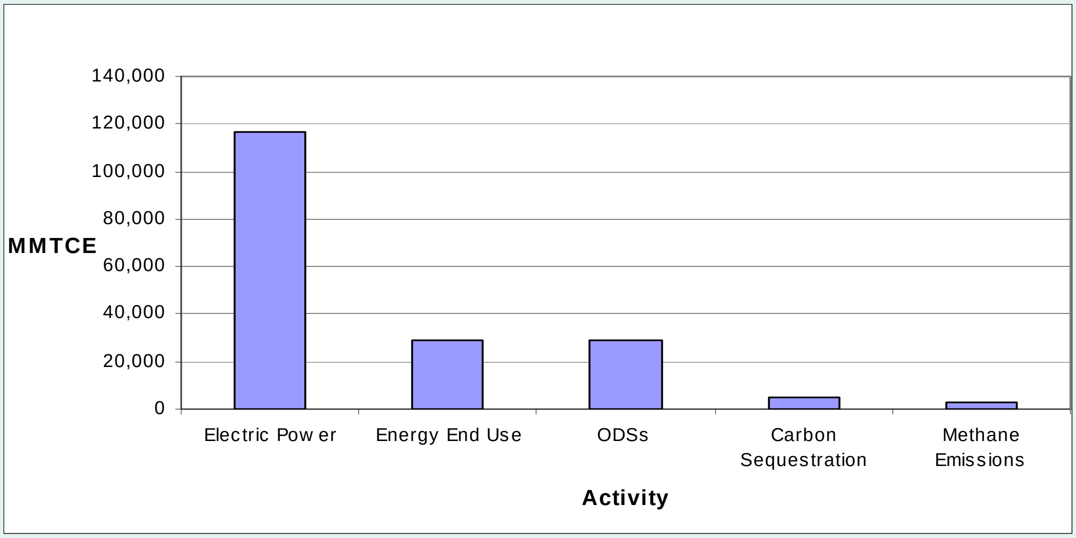


Figure 2.5.4c presents the number of entities that are taking part in the voluntary GHG reporting program instituted by the DOE. Organizations that provide electric, gas, and sanitary services made up 138 of the 228 participating organizations. The textile mill products, primary metals, and chemical and allied products industries were the only other sectors that had 10 or more participating organizations.

Utilities in California have been active regarding climate change issues. The Sacramento Municipal Utilities District (SMUD) has a goal of generating 10% of their total electricity from renewable energy by 2006, and 20% by 2011 (SMUD, 2004). These goals are more ambitious than the requirements of California's Renewable Portfolio Standard (RPS), of which small municipal utilities are not yet required to take part. In the future, it is likely that updates or changes to California's RPS legislation will no longer exempt small municipal utilities.

Figure 2.5.4.b. Emissions reductions per Project, by Activity*, in 2002.
(Source: DOE, January 2004c)



*Electric power activities due to reductions relating to carbon content and efficiency in generation, transmission and distribution.

In June 2004, SMUD released a broad solicitation related to its RPS and green energy pricing programs. They expect to initiate some contracts in 2005. The district has simple renewable energy programs for residential customers, including the conversion of rental systems to purchased systems. They also have simple interconnection agreements, as well as net metering benefits for systems that are less than 1 MW. SMUD is also working with area builders on systems for new homes, and with the DOE Zero Emission Homes (ZEH) Program. These homes reduce residential energy bills by more than 60% (SMUD, 2004).

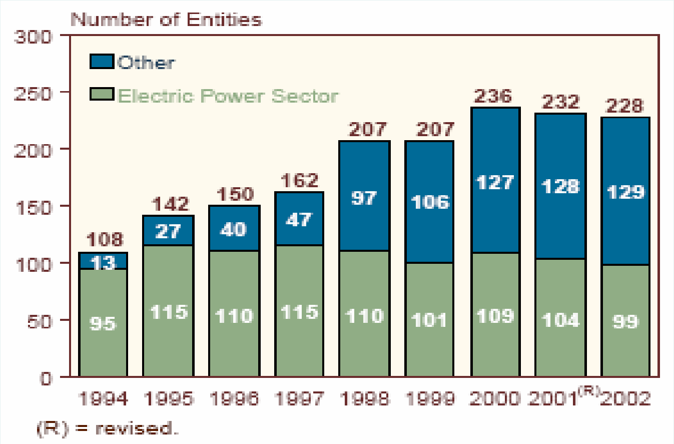


Figure 2.5.4.c. Number of electric power sector and other entities submitting reports to the Voluntary Reporting of Greenhouse Gases Program.. (Source: DOE, January 2004c)

SMUD is also working on expanding the Solano Wind Farm. They have replaced the initial turbines with more advanced technology, including tubular (instead of lattice) towers that reach more than 400 feet. The slower, taller turbines have increased efficiency and reduced bird mortality (SMUD, 2004).

The district purchases biomass from Washington State and plans to purchase waste from Sacramento County landfills. SMUD estimates that half of these 200,000 tons of waste could be utilized to offset 10 MW worth of non-renewable energy. This program would also be able to make use of waste that currently goes to Nevada. Other programs are also making use of local dairy farms. SMUD estimates that the area's farms could supply nearly 2 MW of power using anaerobic digestion. They are forecasting a 5 year payback period, and currently 5 dairy farms are participating (SMUD, 2004).

Pacific Gas and Electric (PG&E) has been involved in GHG mitigation activities since 1977. These activities include fuel switching to natural gas, demand side management (DSM) programs and energy efficiency programs (DOE, 2005c). PG&E has also replaced diesel pumps in the Central Valley with less carbon-intensive electric pumps (San Martin, 19 January 2005). They have also upgraded many of their pipelines to reduce natural gas emissions.

2.6. Climate change policy

Increasing scientific consensus on the contributions of anthropogenic GHG emissions to climate change has prompted various forms of public policy debate in attempts to address current GHG emissions trends. While these debates have not resulted in limitations affecting California's municipal utilities, regulations are on the horizon. This section is an overview of current public policy at various jurisdictional levels. It provides context for the discussions of mitigation approaches (Chapter 6) and the decision processes (Chapter 7).

2.6.1. International policy

International policy concerning GHG mitigation is primarily based on the actions of the United Nations Framework Convention on Climate Change (UNFCCC) which was established at the Rio Earth Summit in 1992. The Third Conference of Parties (CoP) of the UNFCCC produced the Kyoto Protocol, the international doctrine for addressing climate change. The design of the Kyoto protocol is based on the Montreal Protocol for dealing with ozone depleting substances (ODSs) and the 1990 US Clean Air Act Amendments for dealing with SO_2 emissions.

In response to increasing concern about climate change, the international community began to address GHGs by forming the Intergovernmental Panel on Climate Change (IPCC) in 1988. The IPCC formed three working groups (WGs) and a task force to analyze each of the following:

- WG I – assess the scientific aspects of climate change;
- WG II – assess the options for adaptation;
- WG III – assess the options for mitigation; and
- Task Force – responsible for the IPCC National Greenhouse Gas Inventories Program

Approximately every six years, the IPCC releases a new assessment, with updated reports from each of the WGs. The second assessment was released in 1995, and prompted the conference that negotiated the Kyoto Protocol. The third assessment was released in 2001, and the fourth assessment is scheduled to be released in 2007.

The UNFCCC met in Kyoto in 1997 to finalize a multilateral treaty with specific reduction targets for the industrialized countries that first agreed to reduction targets at the Rio Earth Summit. The Kyoto Protocol classifies countries as Annex I and non-Annex I. The Annex I category consists of developed countries, and includes the United States and Canada, the European Union, Russia and Eastern Europe, as well as Japan and Australia. Non-Annex I countries are mostly from the developing world.

Annex I countries agreed to reduce their emissions about 5% from 1990 levels, between the 2008 – 2012 commitment period. Some countries, like the U.S. at 7% (a signatory to the Kyoto Protocol, but without ratification), and the EU at 8%, agreed to make deeper cuts, while other countries, such as Australia would actually get to increase their emissions. After this period, Annex I countries would make further cuts, while non-Annex I countries would begin to make required reductions. For the treaty to enter into force, at least 55 countries representing at least 55% of Annex I-country emissions would need to sign and ratify the Protocol.

Once ratified, the treaty would become international law and have the same status as Geneva Convention, the laws of the World Trade Organization and other treaties. The final ratification was signed in October of 2004 and the Kyoto Protocol entered into force on February 16, 2005. However, it was without U.S. participation since the U.S. did not ratify the Protocol.

The Protocol has four tools, known as flexibility mechanisms, to allow Annex I countries to cooperate with other nations to reduce their GHG emissions. The first mechanism allows Annex I countries that have signed and ratified the protocol to trade emissions credits amongst themselves. The second mechanism, Joint Implementation (JI) is similar to emissions trading, except that it is project-based, not program-based (Hunter et al., 2001). In JI projects, entities that are not countries can trade emissions credits amongst themselves, but only after these projects have occurred (Hunter et al., 2001). The third mechanism allows entities to sign agreements to aggregate their targets and emissions. The fourth mechanism, the Clean Development Mechanism (CDM), allows Annex I countries to meet their targets by setting up sustainable projects in non-Annex I countries (Hunter et al., 2001).

The UNFCCC has developed guidelines for various-sized CDM projects. These include:

- Validation and registration of CDM project activities;
- Methodologies for afforestation and reforestation CDM projects; and
- Methodologies for small-scale CDM projects

Of the flexibility mechanisms, CDM projects are of most interest for small municipal utilities because they offer the most promising opportunities for future participation through investment in existing projects. The UNFCCC web site lists CDM projects that are operational or have been completed. So far, only two projects are operational.

2.6.2. The European Union Greenhouse Gas Emissions Trading Scheme

The European Union Greenhouse Gas Emissions Trading Scheme (EU ETS) started operations in January 2005 as the world's largest and first, multilateral trading operation. The first phase of the EU ETS, from 2005 to 2007, will cover more than 12,000 emitting sources that make up nearly half of all EU ETS emissions. These sources include the major emitters within the power and heat generation sector, as well as large emitters within the industrial and manufacturing sectors.

The number of initial allocations for GHG emissions is set by each country's National Allocation Plan (NAP) which is derived from an organization's average emissions during the baseline period of 1998 to 2003 (AEA Technology, 2004). Each country must keep track of its emissions reductions targets as set by Kyoto when allocating emissions allowances to its own emitting sources. Emissions reductions projects must satisfy the eleven criteria contained in Annex III of the Kyoto Protocol. Countries can also take advantage of the JI and CDM projects denoted in the Protocol.

The trading scheme is flexible and has few rules. Emission allowances can be traded directly between parties, or indirectly with a broker. The EU ETS will track the number of emission allowances (in an electronic registry) by country but will not track trading activity. The penalties for exceeding emission allowances are scheduled to start out at 40 Euros per ton during the initial phase, and increase to 100 Euros per ton in 2007. This strategy will be effective as long as the price of a carbon emission allowance remains below the applicable penalty on a per ton basis.

The specific setup of the scheme should enable European entities to trade with entities in non-EU countries, including American entities such as municipal utilities. The EU ETS brochure states that the scheme will encourage trading between the EU and certain US states. As the amount of trading increases across the continent, the EU and US industry may exert additional pressure on the US government to enact regulations on carbon emissions.

2.6.3. U.S. national policy

Relatively little legislation has been enacted at the U.S. national level, but the amount of policy discussion has significantly increased in recent years (Rabe, 2002). The current policy, the 2002 Global Climate Change Initiative, is a voluntary policy designed to:

- Improve the federal reporting mechanism for GHG inventories with the Department of Energy's Voluntary Emissions Registry (initially created in Section 1605(b) of the Energy Policy Act of 1992) (DOE, 2004b);
- Create voluntary mitigation goals to reduce the national carbon intensity (defined as a rate in units of tons of carbon equivalent per unit of gross domestic product) to 18% by 2012 (Forbes, 2003); and
- Subsidize research and development of energy conservation, renewable energy and geological sequestration technologies (Goulder, 2004; DOE, 2004b).

Additional initiatives for businesses to voluntarily reduce emissions were recently developed through the Climate VISION and Climate Leaders programs. The focus of these programs is to create a transparent means of recording voluntary reduction efforts (DOE, 2004b). This current policy emerged from the 2001 National Climate Change Technology Initiative policy announcement and exists in conjunction with the Hydrogen Fuel Initiative of 2003 (Smith, 2004).

Other federal research and development programs currently in place through the Department of Energy's Sequestration Program include the following:

- Pilot projects and funding of regional partnerships of geological sequestration into saline aquifers, unmineable coal seams, enhanced oil recovery, and natural gas fields;
- Development of measuring, monitoring, and verifying methodologies of stored CO_2;
- Reforestation experiments on reclaimed federal lands;
- Carbon dioxide capture technologies for utility and industrial sources;
- Energy efficiency and renewable energy sources;
- Landfill methane recovery; and
- CO_2 conversion to usable or benign forms through biological and chemical processes.

The voluntary reporting and mitigation approaches mentioned above, coupled with research and development subsidies, are best exemplified in the private and public sector-invested project FutureGen. FutureGen involves the design, construction and operation of a prototype 275 MW coal gasification-fueled power plant equipped with CO_2 capture and geological sequestration capabilities. GHG sequestration rate goals are noted to be one million tons per year with a minimum of 90% of generated CO_2 sequestered (Smith, 2004).

2.6.4. Regional policy

Much of the current U.S. domestic policy effort at addressing GHG emissions is at the state level of government – both individual states as well as regional coalitions of states (Rabe, 2002). Regional policy making is relevant to utilities for two reasons. First, it represents multi-jurisdictional agreements that are indicative of possible national policy approaches. Second, member states of regional coalitions often adopt mandated policy within their own jurisdiction (as exemplified in Pew Center, 2004). Current policy efforts by three regional initiatives are worth noting.

Regional initiatives of note

- **The New England Governors and Eastern Canadian Premiers (NEG/ECP):**
  An agreement to a Regional Climate Plan establishing reduction goals of attaining 1990 levels by 2010, 10% less than 1990 by 2020, and 75-85% less than current levels long term.
- **West Coast Governors' Global Warming Initiative:**
  The initiative promotes the improvement of fleet vehicle GHG emission rates; increase of energy supply from renewable resources; adoption of energy efficiency standards for unregulated products; and further incorporation of energy efficiency standards into government building codes.
- **Midwestern States coalition:**
  A collaborative effort to promote research of alternative energy sources, initiate implementation of energy efficiency measures, and develop carbon sequestration projects.

The New England Governors and Eastern Canadian Premiers (NEG/ECP), a coalition of Northeastern states of the U.S. and Canada that share energy and transportation networks and air basins, have agreed to a Regional Climate Change Action Plan that establishes regional emission reduction goals of reaching 1990 GHG levels by 2010, 10% less than 1990 levels by 2020, and 75-85% less than current levels in the long term (West Coast Governor's Global Warming Initiative, 2004). The plan is structured similarly to past successful efforts by the same group to curtail acid deposition and mercury pollution. Like these efforts, the Regional Climate Change Action Plan creates a regional GHG emissions inventory and registry, outlines mitigation options, and explores the feasibility of a regional trading program (NEG/ECP, 2001).

The West Coast Governor's Global Warming Initiative, is a collaborative effort begun in 2003 by California, Washington and Oregon. Though currently in a research and development phase, the initiative is promoting the improvement of fleet vehicle GHG emission rates; collaborative purchasing of hybrid vehicles; implementation strategies to increase retail energy sales from renewable resources; adoption of energy efficiency standards for products not regulated by the federal government; and further incorporation of energy efficiency standards into government building codes (West Coast Governor's Global Warming Initiative, 2004). Additionally, development of standardized GHG emission inventories, reporting protocols and accounting methods are under development under this initiative (Pew Center, 2004).

In 2003 Midwestern States, assisted by the Pew Center on Global Climate Change, began formulating policy solutions to climate change by comparing individual state's implementation programs (as mandated by the Clean Air Act (CAA)) in order to determine policy effectiveness (Pew Center, 2003). The primary objectives of this regional collaboration are to develop alternative energy sources (e.g., ethanol, switchgrass, dairy and swine farm methane), energy efficiency measures, GHG inventories and trading programs, and carbon sequestration projects. Though the Midwestern states have not reached a collaborative agreement to date, the individual state efforts are forming a framework by which a regional initiative may take shape (Pew Center, 2003).

Regional cooperation may also strengthen policy through recently filed lawsuits. In August 2004, the states of Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, and Wisconsin, and the city of New York filed suit against five of the largest electric power utilities, located mainly in the Midwest. These five companies represent 25% of the emissions from U.S. electric power utilities, and 10% of the emissions from all human activities in the U.S. The lawsuit calls for the utilities to decrease their CO_2 emissions to reduce the effects of global warming. In July 2003, Connecticut, Massachusetts and Maine sued the U.S. Environmental Protection Agency (EPA) in federal court to force the classification of CO_2 as a criteria pollutant. If the lawsuit is successful, it would regulate CO_2 emissions under the Clean Air Act and limit the amount that could be emitted to the atmosphere each year (Massachusetts State Attorney General's Office, 2005).

2.6.5. State policy

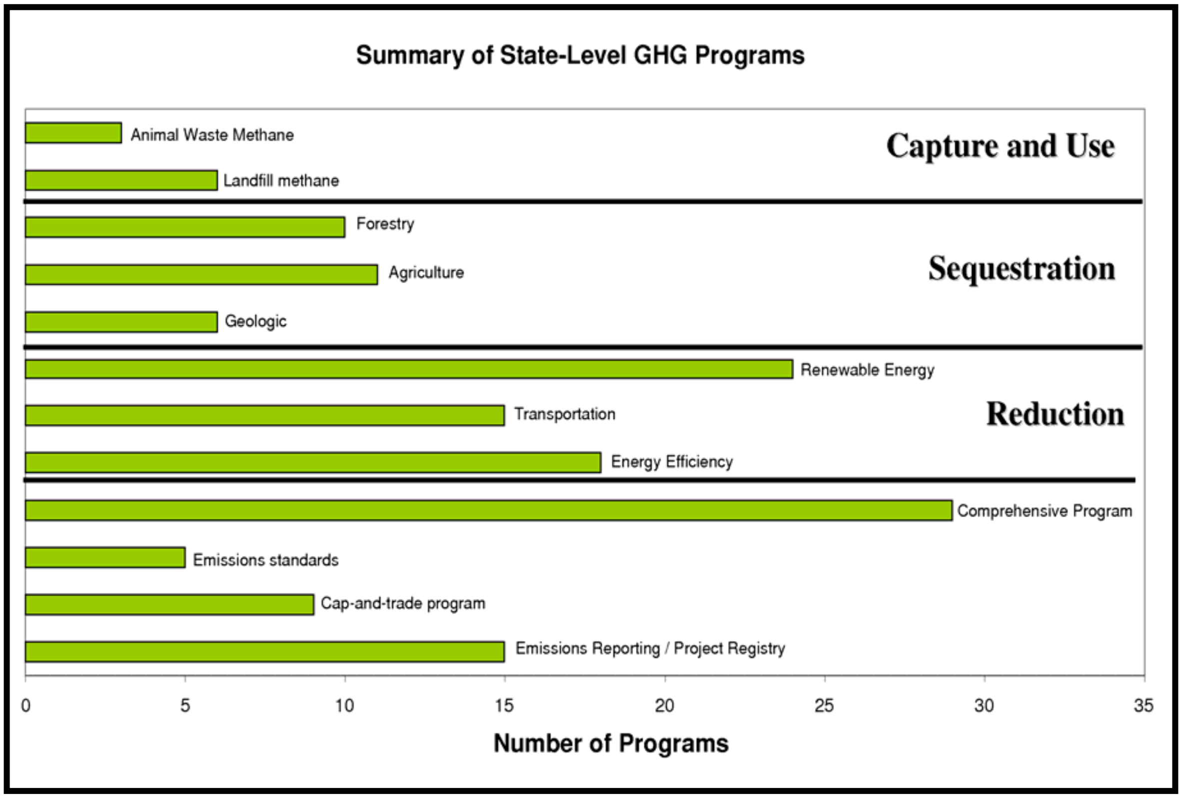
By far the majority of GHG mitigation policy is being developed at the state level. A growing number of states are enacting policies to directly and/or indirectly mitigate GHG emissions within their jurisdictions (or within an entire air basin via membership with regional efforts) (Rabe, 2002). Several states are using their authorities over transportation, land use, utilities and taxation to accomplish this goal (Pew Center, 2004).

Figure 2.6.5 is a compilation of various state-level policies that are either being enacted or are in a developmental stage. It illustrates where current policy is directed and, in turn, may provide an indication of future policy direction. As noted by the graph, the vast majority of current policy efforts are directed towards reduction measures such as energy efficiency and renewable energy portfolio standards. On an individual basis, the state programs are too numerous to address here, but the readers should note that:

- Some states, such as New York, are developing GHG emission cap-and-trade programs as part of their existing GHG registries (Rabe, 2002);
- Other states are pursuing mandatory emission reduction standards [e.g. Assembly Bill (AB) 1493, California's GHG mobile emission standards for 2009 model year vehicles (West Coast Governor's Global Warming Initiative, 2004)]; and
- Oregon is considering legislation to set CO_2 emission standards and create offsetting measures for newly constructed power plants. Washington is contemplating similar measures (Pew Center, 2004).

Policy analysts have expressed both apprehension and enthusiasm toward this state-level activity. State and regional policy activities are partially filling gaps at the national level (Rabe, 2002; Pew, 2004; and Goulder, 2004), however, there are concerns that disjointed state efforts will result in a patchwork of uncoordinated policies and therefore lack the effectiveness of a comprehensive effort (PPI, 2004 and Pew Center, 2003).

Figure 2.6.5. Summary of current GHG mitigation policies at the State level.



Adapted from Pew, 2004.

2.7. Future policy directions

Some policy analysts speculate that future legislation for sources such as utilities could resemble federal criteria air pollutant regulations – a mix of command-and-control as well as market-based regulations such as tradable permits (Cole, 2002). International policies under the Kyoto Protocol and recent actions at the U.S. state- and regional- levels support this prediction (see discussion above). Other analyses suggest future policy in the form of a carbon tax to fund the advancement of mitigation technology – a key factor for lowering mitigation costs (Goulder, 2004). Predicting the exact make-up of future GHG policy is not possible. However, this section of the guide explores the potential consequences to BWP and other small municipal utilities in California that act early to mitigate GHGs under different policy actions.

2.7.1. Potential state and/or federal policy approaches

This section describes the three broad categories of policy approaches that could be used to regulate GHG emissions:

1. Command-and-control
2. Market-based programs
3. Tax-based programs

Command-and-control

Initial regulatory efforts used command-and-control regulations that proved successful at a time when an existing, sizable group of high emission sources came into compliance under mandated emission control technologies. Proponents of command and control regulation note that since 1970, this policy approach has successfully improved air quality (Clifford, 2004). However, as the marginal cost of reducing additional emissions increased and standards remained unattained in many areas, these regulations politically hindered further progress (Goklany, 1999). Furthermore, critics argue that command-and-control regulations stymie the advancement of mitigation technologies because little or no incentive exists for business investment in research and development (Hockenstein et al., 1997).

Market-based Programs

From 1974 through to the 1990 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) addressed concerns of effectiveness and efficiency about command-and-control by introducing market-based programs such as "netting," "offsets," "bubbles," and "cap-and-trade permits" (Cole, 2002). These approaches facilitated lower compliance costs than command-and-control governance and have been well received by the public and industry alike (Tietenberg, 2002). However, to assure certainty and transparency in the market, the programs require a more aggressive and, therefore, more expensive monitoring and enforcement mechanism (Cole, 2002). Additionally, market uncertainty is introduced due to the limited property rights associated with emission credits or permits. The government can remove permits and credits from circulation if air quality standards are not being met thus potentially limiting the success of fully developing the pollution market (Tietenberg, 2002; Cole, 2002). A final criticism of market-based programs is the potential for concentrating market power with existing firms through the allocation of permits, thus reducing the competitiveness of the market and thwarting the introduction of newer, cleaner technologies (Woolf & Biewald, 2000).

Taxed-based Programs

The structure of tax-based programs is similar to that of market-based programs; the price structure is created such that a known price is associated with emitting the applicable pollutant(s) (Tietenberg, 2002). The primary difference between the two is that a tax-based program allows the government to set the price of the pollutant(s) and adjust it in response to new information or unattained standards. However price-setting by the government rather than the market is not necessarily more efficient (Cole, 2002), and it is politically unpopular. Still, with a lack of sufficient certainty to facilitate a robust market, a tax-based program might prove a good surrogate to market-based programs (Tietenberg,2002).

The costs and benefits of these three general policy approaches should be thought of within the complex and uncertain nature of GHG emissions and climate change policy. It is likely that a combination of policy approaches will be enacted with a strong emphasis on a market-based program. The following issues should be taken into account by utilities that either monitor or become actively involved with the policy formulation process:

- *Initial Permit Allocation.* In order for a pollution market to develop properly a government agency needs to allocate initial rights accurately. Historically, this was based on an accurate inventory of emissions. Assuming this strategy is repeated, it is imperative for low GHG-intensive energy generators to petition for allocations to be based on historical output of electricity rather than emissions (San Martin, 19 January 2005). To allocate based on emissions would result in a skewed distribution favoring utilities that have older and "dirtier" technology and fuel use.
- *Setting the GHG reduction goal.* Historically, for air pollutants, a health-based standard has determined this goal. However, GHG are not immediately a health concern and therefore another methodology is needed. The infancy of climate change science could result in national or state reduction goal adjustments; this possibility could send a signal of uncertainty to investors and possibly disrupt the development of a robust GHG market.

➢ *Monitoring and Enforcement.* For traditional means of reducing GHG emissions the cost of monitoring and enforcement may not be that much greater. This is due in large part to the fact that the infrastructure to monitor and enforce is often times already in place due to the regulatory nature of the six criteria air pollutants (e.g., continuous emissions monitors at the source and a central administrative database that compiles emissions data). However, less traditional means of reductions, such as forestation and geological sequestration do not necessarily have this form of economies of scale to benefit from.

2.7.2. Potential barriers to federal regulation of GHGs

Any regulated market, such as an emissions trading program, needs to balance the goal of reductions (by way of regulation) with the incentive to participate (by way of not over-regulating the market). The lack of clear reduction goals and short-term political changes in the existing U.S. national program has created an imbalance, resulting in economic uncertainty for organizations participating in voluntary GHG mitigation/reduction programs. For example, the current overhauling of the Section 1605(b) registry, particularly the change in baseline year from 1990 to 2002, voided the federal recognition of all reduction projects that were registered prior to 2002 (DOE, 2004b). This baseline year shift was made to offset the sizable economic growth that the U.S. experienced during the 1990s which would have made it more difficult to show progress towards the 18% reduction of greenhouse intensity set forth by the 2002 Presidential Initiatives (San Martin, 19 January 2005). The radical and sudden change in the baseline year has decreased incentives and caused uncertainty for industry with respect to volunteering any further reduction investments (DOE, 2004b).

The current trend toward state- and regional-level market-based programs in the U.S. causes uncertainty for participants due to questions about the legal standing of these governments to allocate carbon permits. In the future, the federal government might have sole authorization over (i.e., ownership of) carbon in the U.S. Therefore, programs that allocate CO_2 property rights (i.e., permits or credits) could be invalidated upon federal declaration of improper state or regional apportionment or upon reallocation within a created national program (San Martin, 19 January 2005). A section within the California H&S Code that addresses the California Climate Action Registry (CCAR) could be construed as recognition of this possible outcome: "[California] hereby commits to *use its best efforts* to ensure that organizations that establish GHG emissions baselines and register emissions…receive appropriate *consideration* under any future international, federal, or state regulatory scheme relating to GHG emissions" (CA H&S Code, §42801(e), 2004) [Italics added for emphasis].

Despite the uncertainty in federal regulations,

Obstacles to GHG regulation

A hindrance to the development of federal legislation aimed at regulating GHGs is that gaseous compounds such as CO_2 and CH_4 that make up the family of GHGs are not defined as 'air pollutants' by the EPA, based on criteria set forth in the CAA [Sections 108 (a)(1)(A) and (B)]. Does this lack of designation prevent the regulation of GHG emissions?

In August of 2003, the EPA, in response to a demand by a group of states for a federal regulation of GHG emissions, declared that it lacked the CAA-derived authority to regulate GHGs as they are not defined as 'air pollutants.' As a result, several northeastern states brought a suit to the D.C. Circuit Court of Appeals contesting the agency's ruling and arguing that lack of federal regulation will result in ineffective and disjointed state-level regulations (Kosloff & Trexler, 2004).

At this juncture it appears that in order for federal regulatory policy to develop, the CAA Section 108 designation of GHGs, such as CO_2, as air pollutants would need to be made. However, an 'air pollutant' by definition has an "adverse effect on public health or welfare," associated with it (EPA, 2003), a risk that is only indirect (by way of deleterious effects of climate changes) in the case of GHGs.

utilities still have an interest in mitigating their GHG emissions. The power sector is a major contributor to the U.S. GHG inventory, and as such, is a likely target for future regulations and focused public scrutiny. It is also an untapped source of low- cost mitigation opportunities, such as energy efficiency improvements and investments in renewable energy portfolios. For California municipal utilities a second benefit to investing in renewable energy is the recent discussion in the state legislature centered on bringing municipalities up to the same renewable energy standards as Investor Owned Utilities (IOUs).

Furthermore, though future regulation specific to GHG emissions is difficult to predict, recent trends in regulatory frameworks point to eventual regulation of GHG emissions. Both state and federal air quality regulations, beginning in the late 1980s, have used a mixture of command-and-control and market-based mechanisms. Utilities may be faced with a similar mixture of regulations and the development of a mitigation strategy needs to consider the feasibility of claimed reductions within such a regulatory context. The high percentage of GHG emissions generated by the power sector may increase public scrutiny of power generators. Utilities with a GHG mitigation strategy in place are less likely to receive the brunt of public scrutiny as the issue of GHG emissions and global climate change escalates. This chapter provides background information that may directly or indirectly affect a utility's decision to mitigate their GHG emission liability.

FOR FURTHER INFORMATION ON:

- **Climate change and predicted global impacts**
  - ACIA (2004). Impacts of a warming arctic. Arctic climate impact assessment. New York, NY: Cambridge University Press. http://www.acia.uaf.edu
- **Climate change and California impacts**
  - Union of Concerned Scientists. (2004). *Climate change in California: Choosing our future.* [Brochure] Cambridge, MA: The Union of Concerned Scientists. http://www.climatechoices.org/
  - Field, C.B., Daily, G.C., Davis, F.W., Gaines, S., Matson, P.A., Melack, J., and N.L. Miller. (1999). *Confronting climate change in California: Ecological impacts on the golden state.* Cambridge, MA: The Union of Concerned Scientists; Washington D.C.: The Ecological Society of America. http://www.ucsusa.org/climatechange/ccreport.html
- **Climate system, climate research, and carbon cycle**
  - Hadley Centre for Climate Prediction and Research
    United Kingdom
    http://www.met-office.gov.uk/research/hadleycentre/index.html
- **Existing GHG mitigation activities**
  - U.S. Environmental Protection Agency
    Global Warming – Resource Center: Case Studies.
    http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterToolsCaseStudies.html
- **Climate change policy**

The Pew Center has done an extensive review of various policy aspects of climate change.

- Pew Center on Global Climate Change
  2101 Wilson Blvd, Suite 550
  Arlington, VA 22201
  Tel: (703) 516-4146
  http://www.pewclimate.org

- U.S. Department of Energy
  Office of Fossil Energy
  National Energy Technology Laboratory
  626 Cochrans Mill Road
  P.O. Box 10904
  Pittsburgh, PA 15236-0940
  Tel: (800) 553-7681
  http://www.netl.doe.gov

➢ The international world and climate change

- United Nations Framework Convention on Climate Change
  Haus Carstanjen
  Martin-Luther-King-Strasse 8
  D-53175 Bonn
  Germany
  Tel: (49-228) 815-1000
  http://iunfccc.int/

  For information on CDM projects:
  http://cdm.unfccc.int/

➢ The business world and climate change

- Carey, J. (2004). *Global Warming: Why business is taking it so seriously*. Business Week, Aug 16, 2004. http://www.businessweek.com/print/magazine/content/04_33/b3896001_mz001.htm?mz

3. Assessing Existing Emissions and Setting a Mitigation Goal

An essential precursor to taking action to mitigate climate change is tracking and reporting of an organization's GHG emissions. At the planning stage, a rough estimate of a utility's GHG emissions is sufficient for setting a mitigation goal which will facilitate evaluation of abatement options. The estimation process will also help a utility identify potential mitigation opportunities. Eventually, though, the utility needs to complete a precise inventory of its emissions. Available protocols for this process are summarized in Section 3.1 while Section 3.2 provides examples of mitigation goals set by other facilities and offers recommendations for the California's small municipal utilities in setting these targets.

3.1. GHG emission inventories

A variety of GHG emissions inventory and certification protocols and guidelines have developed under domestic markets for GHG emission trading. These include various state- and regional-level reporting and registry programs, the U.S. DOE's 1605(b) voluntary reporting program, international GHG trading programs under the Kyoto Protocol, and industry sector groups. The basic equation used in most inventory protocols and guidelines is given below (DOE, 2004e):

$$C_{eq} = \sum \left[(AD)\ (EF)(12/44) \right]$$

Where:
C_{eq} = Carbon equivalent emissions from fossil fuel combustion (Units: "million MT")
AD = Activity data based on net fossil fuel usage (Units: "MMBtu")
EF = Emission factor (Units: "MT CO_2 / MMBtu")
12/44 = molecular weight ratio of carbon to carbon dioxide

Despite using the same fundamental, underlying calculation, these protocols and guidelines can produce very different outcomes because they draw different boundaries for the scope of the accounting procedures. Some GHG inventory reporting programs, such as the U.S. DOE's 1605(b), are designed to accommodate a variety of available accounting protocols whereas other programs, such as the Chicago Climate Exchange (CCX), use a specific protocol due to the potential economic value attached to the resulting inventory and reduction estimates (IPIECA, 2003). The inventory protocol selected will depend on the motivation and goals that the inventory is meant to support.

A strategy often used by organizations not actively involved with specific market programs is to comply with more stringent methods and protocols (e.g., the California Climate Action Registry (CCAR) Protocol) with the expectation that, by default, the organization will achieve compliance under less stringent protocols (e.g. the DOE's 1605(b) Reporting Guidelines) (San Martin, 19 January 2005). In addition, using multiple methods and comparing the results may strengthen the credibility of the selected estimate (DOE, 1997).

Table 3.1 describes key methodological attributes that are common for emissions baseline inventories (Keith, et al, 2003). Most stringent protocols have all five attributes: relevance, completeness, consistency, transparency, and accuracy, as detailed in the table.

Table 3.1. Key methodological attributes of current inventory guidelines and protocols.

Attribute	Description	Protocols with the attribute
Relevance	Boundaries defined that clearly incorporate GHG emissions (direct, indirect, on- and off-site) associated with the organization in the context of the goals of the inventory (e.g., MERV, internal query, baseline)	• WRI/WBCSD Protocol Initiative • IPIECA Guidelines • 1605(b) General Guidelines • CCAR • IPCC National GHG Guidelines
Completeness	Account for all GHG sources and activities within the defined boundary. Exclusions should be noted and qualified.	• WRI/WBCSD Protocol Initiative • IPIECA Guidelines • 1605(b) General Guidelines • CCAR • IPCC National GHG Guidelines
Consistency	Succeeding inventories should be conducted within the same methodology. Any deviation should be noted and resulting difference should be quantified to facilitate comparative analysis.	• WRI/WBCSD Protocol Initiative • IPIECA Guidelines • CCAR • IPCC National GHG Guidelines
Transparency	Relevant issues of methodology, references, assumptions, and exclusions are to be documented so as to facilitate audit function (e.g., third party verification)	• WRI/WBCSD Protocol Initiative • IPIECA Guidelines • 1605(b) General Guidelines • CCAR • IPCC National GHG Guidelines
Accuracy	Estimates are to be as precise as necessary for the given end-use. Uncertainty and inference limitations should be documented and/or quantified.	• WRI/WBCSD Protocol Initiative • IPIECA Guidelines • NESCAUM • IPCC National GHG Guidelines • 1605(b) General Guidelines • CCAR

There are two points to emphasize about the attributes in Table 3.1. The first relates to the relevance attribute. The boundaries of GHG liability can vary widely among available guidelines and protocols. In many cases, offsite and indirect GHG emissions such as mining, processing, and transporting of fossil fuels to a combustion source contribute to over half of the emissions of a facility (Mills, et al., 1991). However, liability boundaries must be drawn and clearly delineated when developing indirect GHG emission inventories to minimize double counting of emissions as well as increase cost effectiveness.

The second point relates to statistical uncertainty of an organization's exact GHG emissions. Reasonable uncertainty of CO_2 emission estimates in the 3-5% range can be expected from combustion of fossil fuels as long as carbon content of the fuel and the quantity of fuel combusted is known (DOE, 2004e). For the other GHG emissions from fossil fuel combustion (N_2O, CH_4), however, uncertainty is significantly greater because less quantifiable variables (e.g. technology type and combustion characteristics, pollution control equipment, and ambient conditions) need to be considered (CCAR, 2004). Some guidelines and protocols (e.g., CCAR) provide emission factors for CH_4 and N_2O. Others, such as the International Petroleum Industry Environmental Conservation Association, exclude both compounds from combustion derived emission calculations entirely. CH_4 is inventoried as a primary GHG from fugitive emission sources and therefore needs to be accounted for when applicable (e.g., natural gas pipeline).

When calculating baseline emissions, a utility should select a protocol that addresses their goal and motivation for doing the inventory. That is, if the goal is simply to participate in voluntary emissions reporting to the DOE 1605(b) program, then most currently available inventory protocols will suffice. However, it is recommended that a utility choose a stringent protocol that includes the five attributes mentioned in Table 3.1 to ensure an accurate estimate of GHG liability. For organizations in California, the CCAR General Reporting Protocol and the Registry's online emissions calculation and reporting tool, CARROT (Climate Action Registry Reporting Online Tool), should be used for creating an emissions inventory. CARROT is available online at www.climateregistry.org.

3.2. Deciding on a mitigation goal

Once a baseline emissions inventory or estimate is developed (as described in Section 8.1 for BWP), a utility needs to set its mitigation goal(s). Many external and internal organizational variables have a role in determining what this goal should be. Though such decisions are ultimately internal to an organization, utilities should look at reduction goals set by climate change policies as well as targets that are commonly pursued by other organizations to help at the start of the decision process. As Table 3.2.a and 3.2.b show, these reductions goals have ranged from 1% per year to 65% over twenty years.

A utility's overarching motivation for mitigating will determine the reduction goal chosen. For example, a motivation of environmental stewardship might lead to a more ambitious goal, whereas concerns about future regulatory restrictions lead to a target that is similar to those proposed in existing policies. Additionally, the process of inventorying emissions might highlight excellent opportunities for mitigation that are both effective and inexpensive (or even profitable). The GHG reductions from these 'low hanging fruit' can form the basis of the mitigation targets.

Table 3.2.a GHG reduction goals set by climate change policies and programs.
(Source: Pew Center, www.pewclimate.org/belc/ch2m.cfm)

GHG Reduction Program	Reduction Goal	Reduction and Baseline Timeframes
Chicago Climate Exchange (CCX)	Voluntary: 1% per year (Totaling 4%)	• From 2003 through 2006 • Baseline of average emissions from 1998 through 2001
Kyoto Protocol (Implemented February 2005)	Mandated: 5-6% (varies with member States)	• Realized by 2012 • Baseline emissions - 1990
City Local Action Plan Portland, Oregon	Mandated: 10%	• Realized by 2010 • Baseline emissions - 1990
NEG/ECP (NE U.S. & Canada) Climate Change Action Plan	10%	• Realized by 2020 • Baseline emissions - 1990
U.S. Climate Change Plan ("GHG intensity reductions")	Voluntary: 18% [a] (ratio of GHG to GDP)	• Realized by 2012 • Baseline emissions - 2002

[a] –This reduction approach will allow an increase in actual GHG emissions (Pew, 2004).

A municipal utility should consider a mitigation goal that carries a sense of significance to the organization and its stakeholders, yet is reasonable to attain (given the likelihood of increasing marginal costs with each additional percent reduction pursued). The setting of reduction goals by presently participating organizations are often cited as a balance between these two primary considerations. The most common percent reduction goals are between 5-20% with some organizations such as BP Amoco, Dow Chemical, and DuPont extending or repeating their reduction goals once the initial percentage was met (Swisher; 2002). For BWP, the Kyoto Protocol reduction goal of 7% below 1990 emission levels is recommended as a minimum goal. This reduction goal is likely to carry the representative significance mentioned earlier and is easily attainable through implementation of onsite energy efficiency measures and increased investments in a renewable energy portfolio.

Table 3.2.b. GHG reduction goals set by individual organizations. (Source: Swisher, 2002)

Organizations	Reduction Goal	Reduction and Baseline Timeframes
Seattle City Light Municipal Utility (Seattle City Council Mandate)	Mandated: 100% (offset imported power from OR-based supplier)	• Concurrently with purchases • Baseline - purchased emissions
Asea Brown Boveri (ABB)	1% per year	• Each year, 1998 through 2005 • Relative to preceding year
Alcoa	25%	• Realized by 2010 • Baseline emissions - 1990
BP Amoco	10%	• Realized by 2010 • Baseline emissions - 1990
Dow Chemical	20% (energy use)	• Realized by 2005 • Baseline emissions - 2000
DuPont	65%	• Realized by 2010 • Baseline emissions - 1990
Eastman Kodak	15%	• Realized by 2004 • Baseline emissions - 2000
IBM	4% per year	• Continuous • Relative to preceding year
Intel Corporation	10% (of perfluorocarbon emissions)	• Realized by 2001 • Baseline emissions - 1995
Johnson & Johnson	7%	• Realized by 2010 • Baseline emissions - 1990
Shell Oil	10%	• Realized by 2002 • Baseline emissions - 1990
Toyota	10%	• Realized by 2010 • Baseline emissions - 1990
TransAlta Corporation	Stabilize Emissions (at Baseline emissions)	• Realized by 2000 • Baseline 1990 emissions

FOR FURTHER INFORMATION ON:

- **Calculating Baseline Emissions**

  - GHG Protocol Initiative
    Corporate Greenhouse Accounting: Calculation Tools
    World Resource Institute
    10 G Street, NE Suite 800
    Washington, DC 20523
    Tel: (202) 729-7600
    http://www.ghgprotocol.org

  - California Climate Action Registry
    515 S. Flower St, Suite 1305
    Los Angeles, CA 90071
    Tel: (877) 262-2227
    http://www.climateregistry.org

4. Criteria for Preliminarily Screening GHG Mitigation Options

To minimize the complexity of the decision-making process, utilities need to filter the full list of options (Table 2.5.1) to remove those that are not suitable for them to pursue. The following criteria – feasibility, uncertainty, and regulatory restrictions – are thresholds for eliminating unsuitable options. Based on these criteria, the authors of this guide have evaluated the current status of recognized mitigation options listed in Table 2.5.1 and eliminated certain ones. A discussion of this evaluation is provided in Chapter 8.

4.1. Implementation feasibility

- **Criteria:** *Commercial implementation of the option by the utility must be currently feasible.*

Utilities that are beginning their mitigation planning should not consider mitigation options that are not currently feasible to implement on a commercial scale. Some of the mitigation options introduced in Chapter 6 are still in development and have only been tested within an academic setting; functions such as accurate quantification and a high degree of technical certainty that are necessary in a commercial setting are lacking for these mitigation options. In the future, they may be integral components of a utility's GHG mitigation activities, but for now they are not ready for implementation. In part, this is a practical cutoff because current analyses of these options will require making numerous assumptions, or guess-work, to anticipate potential outcomes. The field of GHG sequestration technologies is advancing rapidly, and in-depth analyses involving assumptions about potential future strategies will not be valuable to a utility; resources are better appropriated to strategies that have immediate relevance, such as energy efficiency and renewable energy investments.

4.2. Uncertainty

- **Criteria:** *The option must be relatively certain with respect to its efficacy, and/or the low possibility of negative ramifications that cause net harm to human health or the natural environment relative to the status quo.*

Efficacy issues concern the potential lack of any GHG mitigation benefit as a result of the approach taken. In principle, an activity might be capable of mitigating GHGs, but in actually implementing a project, the utility would not be able to ensure that a net reduction in the amount of atmospheric GHGs is achieved. Sequestration approaches are often subject to this type of uncertainty because of the potential for retransmission of stored carbon. In general, mitigation options that are energy-intensive to set up and operate have higher uncertainty in terms of efficacy.

Activities to abate GHGs often have ancillary effects on human health and the environment. Options that potentially cause severe negative ancillary impacts are eliminated.

4.3. Regulatory restrictions

- **Criteria:** *The option must not be in conflict with existing regulatory policies or frameworks.*

This is a first-pass consideration to remove options that are evidently not going to fulfill requirements of a regulation and/or credit certifying program. Additionally, options that would in part or in whole conflict with existing regulatory policies or frameworks are to be eliminated.

5. Criteria for Evaluation of GHG Mitigation Options

The field of GHG mitigation currently lacks uniform, clearly defined standards for project implementation and performance thresholds. As a result, utilities cannot easily evaluate mitigation options based on straightforward compliance measures. This chapter describes 12 attributes, listed below, of mitigation options that utilities can use as assessment criteria. These attributes will enable utilities to develop economically and environmentally beneficial mitigation plans that are acceptable to stakeholders and prepare the utility for future climate change regulations. They are derived from a literature review of current and proposed mitigation policies and of scientific methodologies,, as well as from interviews and case studies.

The attributes fall under two categories.
(1) Attributes that are central to implementing a GHG mitigation project:

- Project Baseline and Additionality;
- Quantification, Monitoring and Verification (QMV);
- Permanence; and
- Leakage

Regardless of how a small municipal utility mitigates GHGs (direct project implementation, project investment, or purchase of carbon credits), it needs to ensure that the mitigation activity fulfills these four requirements. These attributes are necessary for the utility to receive regulatory and/or monetary credit for its actions.

(2) Other attributes that will influence a utility's choice of mitigation actions. These attributes are listed below in no particular order:

- Project Magnitude
- Economics : Cost per ton
- Existing relationships
- Mitigation Kinetics
- Regulatory acceptance
- Public perception
- Ancillary Impacts
- Stakeholder preferences

5.1. Project baseline and Additionality

- **Criteria:** *The ability to accurately quantify the project baseline is available. Projects must establish that additional GHG reductions/mitigation would not have occurred in absence of the mitigation project.*

A project baseline is an estimate of the amount of GHG emissions that will occur in the absence of the mitigation action that is being considered (IPCC, 2001a). Establishing this baseline is an essential first step in evaluating a mitigation project; it sets the stage for determining if that project achieves additionality – a surplus of GHG offsets beyond any changes in GHGs that would have occurred under the baseline scenario (Watson et al., 2000). The relative challenges and costs associated with calculating the baselines for different types of mitigation are important criteria in comparing options. Box 5.1 outlines key considerations related to project baseline and additionality.

5.1.1. *Project Baseline*

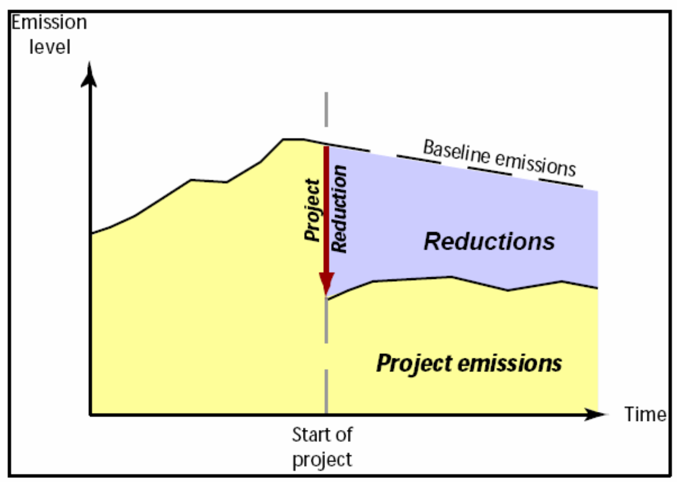
Calculating the project baseline involves estimating the amount of GHG emissions that will occur in the absence a specific mitigation project (IPCC, 2001a). This is the business as usual (BAU) scenario which is illustrated as "baseline emissions" in Figure 5.1.

> **A baseline must be established before a project is begun in order to determine the effect that the project will have on GHG emissions.**

Baseline calculations are partially determined by the physical (e.g. geographic) and temporal boundaries of the project. For example, the geographic boundary of a baseline calculation for a land-based project (e.g. forest or agricultural sequestration) would be that of the land itself. However, the boundary can be difficult to define for other types of projects. The baseline calculation for a project that substitutes renewable energy for fossil fuel-based generation requires determining what type of generation is being replaced. This might not be a clear factor and can require extensive data-gathering to address. Temporal boundaries of the baseline situation should reflect that of the planned project (e.g. if the project will last 40 years, the baseline calculation should cover this length of time as well).

The project baseline is also highly dependent upon the assumptions made about the future GHG emissions activities that will occur in the absence of the project. An incentive exists to inflate the predicted emissions in the BAU scenario to demonstrate a higher net mitigation benefit from the proposed project. However, under the scrutiny of future regulatory standards for GHGs, projects with inflated baseline calculations are less likely (than those with conservative estimates) to be acceptable means of reducing a utility's GHG liability.

Figure 5.1. The baseline and additionality principles. Since the project led to a lower level of emissions (shown in blue as the difference between baseline and project emissions), it has additionality. (Source: Acharya, 2003)



Data from past mitigation projects (e.g., those completed as pilot projects under the Kyoto Protocol mechanisms) have indicated that transaction costs for calculating BAU scenario emissions have been quite high regardless of project size (Sathaye et al., 2001; Minnucci et al., 2001). For small municipal utilities that are likely to seek out relatively smaller-sized mitigation projects, the high transaction costs needed for the baseline calculation can significantly reduce the favorability of a mitigation action.

The issue is further complicated by a lack of regulatory-backed guidelines that would clearly delineate the steps involved for project baseline calculations and simultaneously provide assurances of compliance under future regulation. (By comparison, the calculation of a utility's entity-wide, baseline GHG emissions is straightforward and well-defined for California's utilities under the CCAR Power/Utility Reporting Protocol.)

In absence of this regulatory guidance, utilities should use the GHG Protocol Initiative's "The Greenhouse Gas Protocol: Project Quantification Standard" (Standard). The Standard is still in development, but the current draft provides explicit, step-by-step instructions for calculating the project baseline emissions (BAU) and quantifying the mitigation associated with the project. In terms of acceptability under future regulations, the Standard uses a systematic and rigorous approach to project accounting that is specifically designed to be integrated into a wide range of regulatory requirements.

Utilities should also be aware of efforts by policy makers and scientists to develop standardized procedures and alternatives to the case-by-case approach to project baseline calculations. A manifestation of this effort is benchmarking. (The Standard draft protocol refers to this as the "multiple-project baseline" (MPB) approach and describes how to use MPBs in baseline estimates.) Benchmarks are performance standards from the emissions intensities of different technologies, products, management practices, and sectors. These emissions intensities are denoted in terms such as tons of CO_2/kWh (for electricity production) and tons of CO_2/ton of cement produced, for example. Benchmarks are compared against the expected emissions intensities of a project to determine if additionality is achieved (i.e., the project emissions intensity is lower than that of the benchmark). Multiplying the benchmark intensity by the output levels provides an estimate of the absolute existing emissions (Leining and Helme, 31 January 2000).

Extensive work on developing benchmarks has been undertaken in conjunction with the Kyoto Protocol JI and CDM mitigation mechanisms (described in Chapter 2) e.g., the European Commission's "Procedures for accounting and baselines for projects under JI and the CDM" (PROBASE). (PROBASE, was developed by Probase, a consortium of organizations coordinated by the Foundation Joint Implementation Network.) If a small municipal utility invests in a JI or CDM project, the Probase "Web Based Smart Emission Reduction Estimation Manual" (e-SEREM) is a helpful resource; it guides the user through a standardized baseline determination methodology (Probase, 2003.).

Case studies have also been conducted to calculate benchmark values for specific sectors in specific locations. (For examples, refer to Sathaye et al., 2004; the GHG Protocol Initiative: Resources and Documentation web site, n.d.). Readers should be aware that published and/or government-certified benchmarks are not yet available.

Certain factors with respect to baseline calculations influence mitigation planning.

1. Utilities should favor mitigation options for which benchmark baselines exist or are in development. Within the U.S., most of the work on benchmark baselines has been conducted for the electricity sectors (Sathaye et al., 2004; Minucci et al., June 2001). Therefore, projects that accomplish GHG mitigation through (1) improvements to electricity production efficiencies or (2) substitution of renewable electricity generation for traditional fossil fuel production are more likely to have available standardized baseline calculation methodologies and benchmark values. This availability could significantly reduce the transaction costs associated with these categories of mitigation projects.

2. In California, the CCAR is piloting its Forest Project Protocol (CCAR, 2004). Although the protocol (and the project baseline methodology) is still developing, this is an important source of guidance on forestry-based projects for California's utilities. It can reduce transaction costs associated with these project baseline calculations, and minimize risks associated with these project types by providing compliance guidelines that specifically apply to the target audience of this guide.

3. If benchmarks are not available, or the available ones are not useful (i.e. they are for other project circumstances or have been developed by an organization that lacks applicable authority), utilities will need to conduct a project-specific baseline assessment. Under these conditions, a small municipal utility should prioritize projects within its organization to reduce its own, onsite emissions. Establishing the BAU scenario for these projects will be more straightforward as well as scientifically

and politically defensible than project baseline calculations for outside projects. This is due to multiple factors including; easier access to data, knowledge of the actual (as opposed to assumed) type of electricity generation emissions that the project will avoid or replace, and knowledge and documentation of the utility's business plans and future electricity generation/service projections.

5.1.2. Additionality

When determining project additionality, the basic questions being asked are: Would the emissions reductions (GHG mitigation) *not* have taken place in absence of the project (Chomitz, 2002)? Are the mitigation benefits of the project *additional to* the project baseline (i.e. the BAU scenario)? For real GHG reductions to take place, an organization should only receive emissions credits based on mitigation projects that additionally reduce atmospheric GHGs beyond what would have already occurred. Otherwise, there is the danger of projects being credited that do not aid in obtaining the ultimate goal of reducing overall GHG emissions to the atmosphere. For instance, there was initial reluctance to credit forest conservation projects due to the possibility that mitigation benefits would have been claimed for forests that were not in danger of any land use conversion. Forest conservation projects must show that the forest being conserved would have been logged and destroyed in the absence of conservation project. That is, but for the act of protecting the project area, the project area would have been converted to a nonforest use (CCAR, 2004).

Determining if a project has additionality requires *ex ante* quantification of the expected net reductions/emissions of GHG. Issues relating to quantification of mitigation from a project are described in the next section. The key point of this discussion is that the condition of additionality is essential in any mitigation project. Without it, a project will not be eligible for generating offsets or credits. This applies to projects that a utility plans to initiate as well as to investment or credit trading opportunities.

Box 5.1. Project baseline and additionality

- An accurate baseline estimate for a project is essential.
- The project baseline is the estimate of the amount of GHG emissions that would occur in the absence of the mitigation project.
- The GHG Protocol Initiative's "The Greenhouse Gas Protocol: Project Quantification Standard," is the recommended methodology for estimating project baseline.
- Three factors reduce cost and improve accuracy of project baseline estimates for the target audience:
  1. Benchmark baseline values exist or are in development (e.g. electricity sectors).
  2. The California Climate Action Registry provides specific guidance on acceptable procedures for a project (e.g. the forestry project protocol).
  3. The mitigation project takes place within the utility's organizational boundaries.
- Additionality of a project is essential.
- Additionality is satisfied if:
  1. The planned project would *not* have been completed in the absence of the utility's action.
  2. The project *will* produce a surplus of GHG reductions beyond the project baseline.

5.2. Quantification, Monitoring and Verification

- **Criteria:** *There are accurate quantification, monitoring and verification methods available for the mitigation option.*

Quantification, monitoring and verification (QMV) of GHG offsets are specific steps needed to account for the performance of a mitigation project. As heavily regulated entities, utilities will be familiar with these key factors for demonstrating compliance with a set of standards. QMV steps are also necessary for ensuring utilities receive offset credits and that mitigation projects are achieving real emission offsets. Box 5.2 outlines key considerations related to QMV issues.

In addition to quantifying the level of mitigation expected, a project must be monitored to determine the actual carbon mitigation that occurs during the life of the project. This ensures that project activities are eligible for generating carbon credits. Measurements of ongoing performance must be verified by an independent third party auditor to authenticate the quantity of carbon mitigation that is claimed by the project owner (Mooney, et al., 2002). Most mitigation approaches, such as forest and geological sequestration have accepted techniques for quantifying the amount of carbon that has been sequestered, but others such as soil carbon sequestration are still being tested. There are a variety of QMV techniques that are currently in use, including statistical sampling, laboratory testing, modeling, and testing of sample plots. The technique used will vary depending on the mitigation option being quantified or monitored. For example, quantification of land-use projects can be done by statistical sampling and modeling while monitoring can be accomplished through remote sensing, aerial photography or drive-by inspection.

The challenges with respect to QMV for utilities are similar to those of baseline estimations. There are not yet standardized methodologies; regulatory-backed protocols that delineate precise QMV steps; or clear compliance standards for mitigation quantification. As is the case for baseline calculations, the GHG Protocol Initiative's "The Greenhouse Gas Protocol: Project Quantification Standard" is the recommended protocol for quantification.

Quantification, monitoring and verification costs differ markedly from option to option, and **cost estimates for a project usually do *not* take all three into account.**[2] Utilities should anticipate significant expenses associated with data collection, documentation and reporting that continue for the lifetime of the project. For example, to receive offset credits on a yearly basis, a utility will need to have the amount of mitigation from a project verified annually (Ellis, 2002).

Following the recommendations provided below will help utilities reduce QMV costs and risks of future non-compliance.

1. Utilities need to plan out QMV steps during the project design stage (Ellis, 2002). In particular, the project design should describe the parameters of a project to be monitored for project performance assessment (e.g., electricity generation from a landfill methane capture project) and the measurement techniques to be implemented during monitoring.

2. Utilities should seek out mitigation approaches for which: quantification and monitoring techniques rely upon empirical measurements of GHG abatement, are well-understood, and are already in use. This will produce straightforward and scientifically defensible project accounting that minimizes verification costs and/or future non-compliance risks.

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[2] QMV cost estimates are not commonly available. Those that were identified in the research for this guide are provided in Section 5.8.

3. Projects that use existing data collection and reporting mechanisms (e.g. utility customer billing for efficiency improvement projects; planned inspections of equipment or sites; continuous monitoring equipment already in place) will reduce costs associated with monitoring and verification.

4. Utilities should prioritize mitigation approaches for which project QMV guidelines exist or are in development. In the U.S., the DOE initiated an effort called the International Performance Measurement and Verification Protocol (IPMPV) to "establish international consensus on methods to determine energy/water efficiency savings and thus promote third-party investment in energy efficiency projects" (IPMPV, n.d.). These published protocols give explicit accounting directions for specific efficiency improvement projects. The protocols were initially developed for QMV of energy savings, but they are now being applied to project mitigation of GHGs (e.g. Vine et al., 2002; European Commission, Greenlight Programme, n.d.). The CCAR Forest Project Protocol (2004) is another source of applicable project QMV guidance.

5. Individual mitigation projects that take place within the utility's operational boundaries are likely to have lower QMV costs relative to external projects. Data collection, management and reporting can be centralized and conducted using existing organizational infrastructure. Costs associated with travel might also be minimized. Furthermore, when monitoring or verification indicates that project performance is less than expected or possible, utilities may be better able to respond and address these problems quickly.

Box 5.2. Quantification, monitoring and verification (QMV)

- Quantification, monitoring and verification of GHG mitigation achieved by a project are extremely important. Projects should only be pursued if all three of these steps can be carried out.
- Quantification is the calculation of the net reductions of GHGs due to a project.
- The GHG Protocol Initiative's "The Greenhouse Gas Protocol: Project Quantification Standard," is the recommended methodology for quantifying project mitigation.
- Monitoring of a project measures its ongoing performance in terms of GHG mitigation.
- Verification is the authentication of the quantity of carbon mitigation that is claimed by the project owner.
- Multiple factors reduce the costs of QMV and the risks of future noncompliance for specific types of mitigation projects:
    1. Establishment of a QMV plan during the project design phase.
    2. Empirical quantification and monitoring techniques are available and already being applied.
    3. Existing documentation systems are available for monitoring and verifying the mitigation project.
    4. QMV methods have already been developed and are widely used (e.g. efficiency improvements under the International Performance Measurement and Monitoring Protocol and the CCAR Forest Project Protocol).
    5. The mitigation project takes place within the utility's organizational boundaries.
- Although not required, verification should be conducted by an independent, third party. For the target audience, verification of mitigation projects within California must be conducted by a company certified by the California Climate Action Registry.

5.3. Permanence

- **Criteria:** *An option must have as close to 100% permanence as possible.*

Permanence is the **degree to which GHGs are removed from, or kept out of, the atmosphere** (Murray, 12-15 October 2004); the measure of permanence depends on the relevant temporal scale (e.g., geological sequestration has a finite degree of permanence; over time some emissions retransmission will likely occur). An essential environmental objective of a mitigation project should be to keep CO_2 and other GHGs out of the atmosphere for as long as possible. Utilities should choose mitigation options that permanently reduce GHG emissions because the value of the offsets generated from these projects will not decline. Furthermore, under a GHG regulatory setting, permanent reductions eliminate future risks of falling out of compliance idue to release of the stored GHGs. Box 5.3, at the end of this section summarizes key permanence issues.

A reduction mitigation option, i.e. one that reduces atmospheric GHG emissions through reduced fossil fuel combustion, can be considered *a 100% permanent approach* to abating GHGs. Sequestration projects and certain capture/use approaches (e.g., biomass to product) *do not achieve this complete permanence*. Atmospheric GHGs removed through these types of projects eventually find their way back into the atmosphere through expected retransmission (e.g., logging of a forest) or accidental release (e.g., a fire, or leaks from a geological formation). However, there are activities that have better permanence than others. For example, poorly sited geological storage projects (such as, in semi-permeable geological formations), may result in faster transmission of CO_2 back into the atmosphere; on the order of years rather than centuries.

Although they lack complete permanence, offsets generated through sequestration and capture/use projects still provide valuable mitigation benefits by, (1) removing the amount of GHG for a long enough timeframe to counteract its greenhouse effects, and/or (2) buying time to allow for technology developments that will provide more cost effective mitigation options than those that are currently available.

The first point is true when the duration of GHG removal, the permanence, is considered in terms of the "timeframes of interest to humans" with respect to climate change impacts (Sedjo and Marland, 2003). Costa and Wilson (1996) estimated that carbon needs to remain stored for a timeframe of 55 years, to "counteract the radiative forcing effect of carbon emissions." A more recent and commonly cited storage threshold is a minimum of 100 years (i.e., 1 ton of carbon stored for a minimum of 100 years is considered equivalent to 1 metric ton of carbon emissions reductions) as first defined in the IPCC Special Report on Land Use, Land Use Change and Forestry (Watson et al, 2000). The value of carbon stored for less than this time period should be discounted with respect to reduced emissions. Thus, the bar for 100% storage permanence has essentially been re-calibrated to 100 years from the time of capture.

Currently, no regulatory guidance exists for dealing with impermanent mitigation. Instead trading systems and GHG registries have set eligibility cutoffs for minimum storage of the GHGs to claim offsets. At the international level, three basic proposals for addressing impermanent mitigation have been introduced (Ellis, June 2001):

- Issue "permanent" emission credits based on actual changes in the level of stored carbon as the project progresses, but hold off on providing the majority of credits until the GHGs have been stored for a minimum timeframe;
- Issue "temporary" emission credits that expire at the end of the mitigation project (This is the "Columbian proposal."); and
- Issue credits that are discounted to reflect the environmental benefit of temporary sequestration (This is known as "ton-year accounting").

By no means are these the only options being considered for assigning value to impermanent mitigation. However, these proposals sufficiently illustrate the complexities of dealing with impermanent mitigation achieved through sequestration and certain capture/use approaches. These complexities increase uncertainty about a project's total mitigation benefits and future GHG liability and the timing of awarding of credits or GHG offsets.

To minimize these uncertainties, utilities should follow the recommendations given below when assessing mitigation options.

1. Utilities should prioritize emissions reduction activities which are considered to have 100% permanence. Therefore 100% of the total GHG reductions in a year are completely permanent.
2. Sequestration projects should be sited and designed to minimize retransmission within a 100-year period. Risk can be minimized by selecting projects for which the carbon sink (i.e. where the GHGs are stored) is easily monitored for carbon storage as well as retransmission rates.
3. If a utility pursues a sequestration project, it should be conservative in quantifying mitigation benefits and allow for a margin of error (i.e. retransmission). This up-front liability can be calculated as an indiscriminant down-ward adjustment to the number of offsets received (described below), or by subtracting the likely components of a project that will lead to retransmission (e.g. carbon stored in a a forest preservation project that is located next to a road and thus susceptible to illegal logging).

To account for the GHGs that were initially removed but then retransmitted to the atmosphere before the 100-year cutoff, a discounted value of these GHGs can be calculated. For example, 1 ton of carbon that will be retransmitted to the atmosphere after 10 years could be valued today as 0.5 tons of carbon *reductions*. This relative (present-day) value of impermanent mitigation is the ratio of the value of temporary sequestration to the value of permanent emissions reductions (Lewandrowksi et al, 2004). [3]

Box 5.3. Permanence

- Permanence is the length of time that GHGs are removed from, or kept out of, the atmosphere (Murray, 2004).
- Achieving completely permanent GHG reductions through a mitigation project is an environmental and economic priority.
- In terms of permanence, reduction and certain capture/use mitigation approaches are best.
- The following factors minimize permanence issues.
  1. Prioritization of reduction and capture/use approaches that achieve mitigation that is 100% permanent.
  2. Project siting and design to minimize retransmission and facilitate monitoring of carbon storage and retransmission.
  3. Use of conservative quantification methods for determining mitigation benefits of a project.

3

$$\text{Relative value} = \frac{P\int_{t=0}^{J} rt\, e^{-rt}\, dt}{P\int_{t=0}^{\infty} e^{-rt}\, dt}$$

Equation 5.3 (Lewandrowski et al, 2004)

Where:

P is the payment (value) of 1 metric ton of permanent reductions;
r is the discount rate (This should be based on the regulations/requirements that apply to the utility);
J is the time period (in years) over which the temporarily removed ton of carbon remains out of the atmosphere;
t is time (in years)

5.4. Leakage

- **Criteria:** *Leakage (displacement of GHG emissions to outside of the project boundaries) must be avoided.*

Leakage refers to GHG **"emissions that occur outside the mitigation project boundaries as a result of the project activities themselves"** (Murray, 2004). Leakage situations commonly occur in projects associated with land use changes. For example, the restoration of native tree cover on lands that were being used for agriculture leads to increased demand for agricultural land elsewhere, thus causing clearing of other forested areas to meet this demand. The cleared forest land diminishes or negates the sequestration benefits of the original reforestation project. This type of leakage is referred to as activity-shifting (IPCC, 2000). A summary of leakage characteristics is provided in Box 5.4, while specific leakage issues are discussed in Chapter 6 and Appendix A.

Overall, potential leakage associated with land-based projects has been categorized by the IPCC (2000) into the following types:

1. No/Low leakage potential – projects implemented on land that has few or no competing uses.
2. Moderate/High leakage potential – projects implemented on land that has competing uses or is in dynamic settings.

Leakage can also encompass a larger scale in terms of the cumulative effects on an entire category of mitigation actions, resulting in market effects. For example, widespread conservation of forest as a mitigation approach could reduce world supplies of wood, thus driving up the global market prices, and creating significant financial incentives for logging. At this scale, a small municipal utility's single conservation project is contributing a marginally small amount to increased GHG emissions. In contrast, some projects can have high marginal impacts at a more localized scale. Using BWP as an example, a power generation efficiency project might lead to lower electricity rates for City of Burbank customers, thus reducing customer incentive to conserve. As a result, the project would have a significant marginal leakage impact.

Utilities must consider this factor during their GHG planning stages because leakage can potentially reduce the total amount of offsets that they would receive for certain mitigation actions or completely render offsets ineligible. For example, leakage has been estimated as high as 5-20% of GHG reductions (IPCC, 2001b). Leakage is specifically important for BWP and other California utilities because the CCAR – the organization tasked by state government to establish GHG accounting rules for emitters – requires that leakage losses be included in emissions calculations.

Leakage is a project-specific attribute that must be calculated for each individual mitigation activity that a utility pursues. However, at the planning stage, when utilities are evaluating overall mitigation options (as opposed to specific projects), they do not need to invest resources into calculating precise leakage values for hypothetical project ideas. Rather, they should consider the common leakage problems associated with different mitigation options, and use these factors to help them prioritize one option over another.

Box 5.4. Leakage

- Leakage results from GHG "emissions that occur outside the project boundaries as a result of the project activities themselves" (Murray, 2004). It occurs through two mechanisms:
  1. Activity shifting – a project displaces an activity.
  2. Market effects – a project can alter supply and demand of goods and services leading causing a change in GHG emissions elsewhere.
- Activity shifting leakage is more predictable than market effects and thus, should be the focus of leakage avoidance strategies.
- Leakage occurs most commonly with land-based mitigation projects.
- GHG leakage associated with a project must be quantified (according to the California Climate Action Registry (CCAR) requirements).
- To minimize potential leakage, land-based projects should be sited in areas that have few or no competing uses.
- Leakage, as discussed in this guide, is different from re-transmission of GHGs (i.e., GHGs re-emitted by a project). Re-transmission issues are dealt with in Section 5.3 on permanence.

5.5. Project magnitude

- **Criteria:** *The option will offset the requisite amount of emissions required by the utility.*

The project magnitude is the net amount of GHG offsets (in metric tons of Carbon equivalent (MTCE)) that can be expected from a mitigation project. This should be an early consideration in the decision-making process. Project magnitude issues are outlined in Box 5.5. If a utility plans to initiate its own project, the range of possible magnitudes needs to overlap with the range of their mitigation objectives. Most often, small municipal utilities will find that the minimum practical magnitude for sequestration (e.g. geological injection, agriculture and forest sequestration) and certain capture/use (e.g., biomass to energy or product) options will far exceed their offset objectives. This precludes independent, direct project implementation of these options, but not investment in these through partnerships or credit trading programs. Therefore, if a utility has a certain type of mitigation option(s) in mind, the potential project magnitude range can guide the choices for implementation (e.g., direct implementation, investment, credit purchase).

The range of possible project magnitudes can depend on one or more of the following factors:

- Economic limitations (e.g., a certain project size must be achieved to obtain considerable GHG mitigation , for example : the cost per ton is unreasonably high for geological sequestration projects);
- Physical limitations (e.g., project sizes of landfill or livestock methane capture projects depend upon the available sites for implementation); and
- Policy limitations (e.g., the CCAR only recognizes forestry projects that are greater than 100 acres (CCAR, 2004)).

Project magnitudes for the various mitigation options (described in Chapter 6 and Appendix A) are taken directly from values in the reviewed literature and/or calculated for this guide from available data on potential project sites and information about implemented projects.

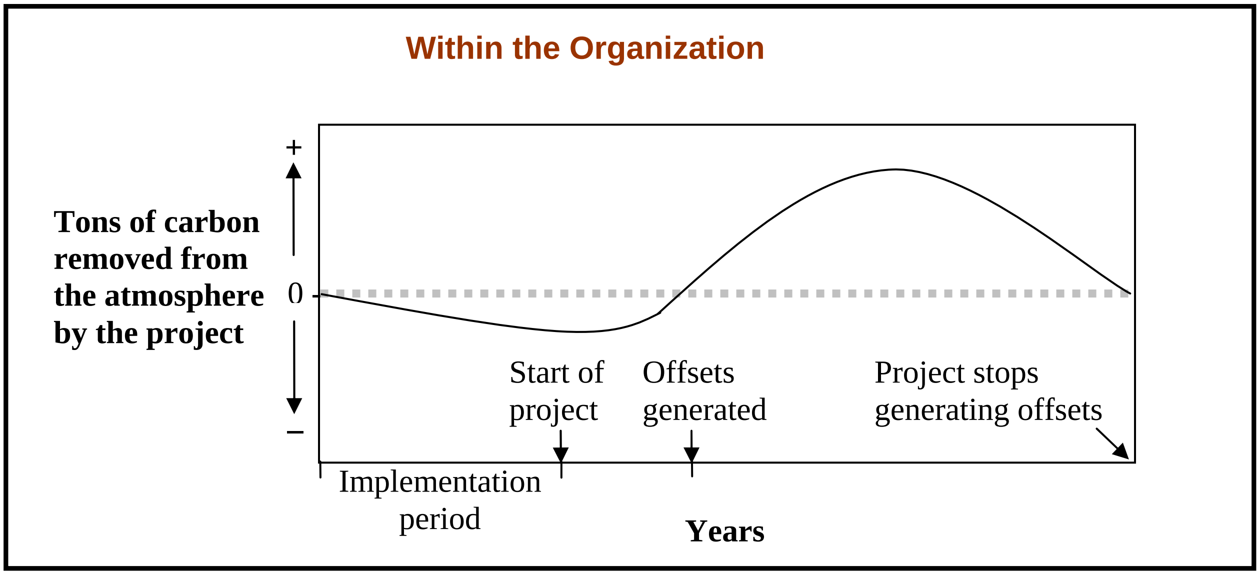
Box 5.5. Project Magnitude

- The project magnitude is the net amount of GHG offsets (in MTCE) that can be expected from a mitigation project.
- Utilities seeking to directly implement their *own* projects should avoid most sequestration and biomass to energy/products approaches because the minimum project magnitudes will be too large for their mitigation objectives.
- For a consortium project or carbon credit purchase, project magnitude is not a central decision-point in mitigation planning.
- Measurement units of project magnitude:
  1. Average amounts (in TCE) of GHGs that can be removed from the atmosphere by a mitigation project of a certain strategy type
  2. For land-based and methane capture strategies; an average amount of sequestration per unit size (e.g. TCE per hectare, or per number of livestock).

5.6. Mitigation kinetics

- **Criteria:** *Abatement activity will occur within the timeframe desired.*

The 'kinetics' of an abatement activity refers to the pattern of GHG reductions over time. This temporal factor can be represented by an emissions timeline of a mitigation project as shown in Figure 5.6. Utilities must consider kinetics in their planning processes because this attribute affects when mitigation offsets due to a project will be received. Key considerations for mitigation kinetics are provided in Box 5.6 at the end of this section. Two factors within this concept are useful attributes to consider in comparing different mitigation options:



5.6.1. Timeframe for offset generation

Timeframe for offset generation refers to the length of time from the start of a project (i.e. once it is up and running) to the point when emissions reductions offsets or credits are available due to that project. Many mitigation projects will have essentially no lag time between start of the project and offset generation. A methane capture-to-generation project might begin offsetting emissions on day one of operation. Investment in an ongoing project or purchase of emissions credits are also examples of 'zero' timeframes. Other projects, such as those involving forestry or agriculture will have some lag time. For example, after the initial planting in an afforestation project, there is a lag of about 2 to 5 years before the trees become net sinks for GHGs.

5.6.2. Longevity

Longevity represents the number of years over which a mitigation project is expected to generate new (additional) GHG offsets. For example, in a forestry project, generation of additional sequestration offsets might continue for decades (e.g., 40-60 years). Longevity should not be confused with project lifetime. A project may stop producing new GHG offsets (thereby capping its longevity) long before it ends (e.g., project monitoring of sequestered GHGs might be required for many more years).

Box 5.6. Timeframe and Longevity

- Timeframe for offset generation is the length of time from the start of a project to the point when emissions reductions offsets or credits are available.
- The start of a project is the point at which it is in place and functioning.
- If immediate receipt of offsets or credits is a priority, a shorter timeframe is more likely to achieve this objective.
- Utilities might be able to defer or push up "realization" of offsets from a project to or from future years (e.g. through amortization), but they should not count on the availability of this option.
- Longevity is the number of years over which a mitigation project is expected to generate new (additional) GHG offsets.
- Longevity is not to be confused with the project lifetime.

5.7. Ancillary impacts

- **Criteria:** *Positive ancillary impacts are orders of magnitude greater than negative ancillary impact and/or negative impacts are absent or close to absent.*

Ancillary impacts are all non-GHG-related effects due specifically to the implementation of a project (IPCC, 2001c). These effects can be positive (benefits) or negative (losses), and can fall under the general categories of human and environmental health, and social impacts (Davis et al., 2000). Box 5.7 outlines key considerations for determining ancillary impacts. Although ancillary impacts do not have bearing upon the GHG mitigation capabilities of a project, they can be a critical issue for small municipal utilities. An excellent example is a mitigation project that relies on a renewable energy transition from fossil fuels to biodiesel and, in turn, leads to an increase in the release of conventional criteria air pollutants – a significant concern for a utility.

Ancillary effects are often very difficult to monetize, so consideration of this factor is qualitative. Common ancillary impacts for the mitigation options are identified in Chapter 6 and Appendix A. However, as utilities narrow in on more specific project alternatives (for direct implementation, investment or credit purchase), they need to conduct a more thorough assessment of ancillary impacts. A scaled-down version of the Environmental Impact Assessment (EIA) methodology provides a good format for this analysis. A summary of the steps involved is provided below, but utilities should consult specific EIA references and guidance documents listed at the end of this chapter.

Descriptions of each project alternative

Required information includes project title, purpose, type of mitigation, size, location, technology to be used, relevant regulations, etc. Utilities should reference Step 1 of the quantification procedures in the GHG Protocol Initiative's "The Greenhouse Gas Protocol: Project Quantification Standard," for the information to be included. The projects should be divided into phases that logically describe their progression. Common project phases for EIAs are (1) pre-construction (planning); (2) construction; (3) operation; and (4) decommissioning.

Impact identification

Utilities identify potential ancillary impacts of each project phase. Descriptions of the mitigation options in Chapter 6 and Appendix A provide help for this process. However, many ancillary effects will be specific to the projects under consideration and utilities should reference an EIA checklist. The "Environmental Checklist" from the California Environmental Quality Act (CEQA) Guidelines provides a good starting point for identifying potentially significant impacts (CEQA, 1998). Factors that are addressed include: air quality, cultural resources, biological resources, aesthetics and more. In using the CEQA or other EIA checklists, utilities should identify both positive and negative ancillary impacts, even though the EIA process looks only at potentially significant *negative* impacts.

Scoping

In the EIA process, scoping steps involve gathering public input on a project as a way of establishing the boundaries of the EIA study (i.e. what are the public concerns). This degree of public information-gathering is not necessary for an assessment of ancillary impacts. However, key stakeholders in the utility should have an opportunity early on in the planning process to learn about the project alternatives and to provide input , including concerns and foreseen potential impacts.

At this point, a utility must compile an *impacts matrix* for each project alternative. The matrix is constructed with phases along the columns, types of potential impacts in the rows, and potentially significant (positive and negative) impacts noted at the intersections. This basic organization of the information should be used to compare and identify the potential impacts associated with the project. If it is apparent that one or more of the projects will have severe negative implications and/or comparisons are not possible (or would be poorly made) without a clearer understanding of the magnitudes of different impacts, a utility should continue with the EIA process until the impacts can be identified.

Investigating potentially significant impacts and using thresholds of significance

The next step is to clarify the degrees of potentially significant impacts through literature reviews, field data collection, interviews of experts, predictive modeling and other analysis techniques. This investigation can be time-consuming and expensive, but is an important step in the process. Utilities should focus on impacts (negative or positive) that are of primary concern and look for ways to alter the project(s) to avert or maximize these ancillary effects. They also need to choose thresholds of significance (TOS) for the investigated impacts. TOSs are usually selected based on regulatory or financial constraints and they provide a standard metric for assessing a specific type of impact due to one or more of the project alternatives. Utilities are not required to use specific TOSs, but ones that are commonly applied are: health-based standards (e.g., pollutant limitations for air emissions or water discharges);

service capacity standards (e.g., traffic level of service, water supply capacity); and ecological tolerance standards (e.g., species carrying capacity, endangered species impacts, loss of prime farmland, wetland encroachment).

Box 5.7. Ancillary Impacts

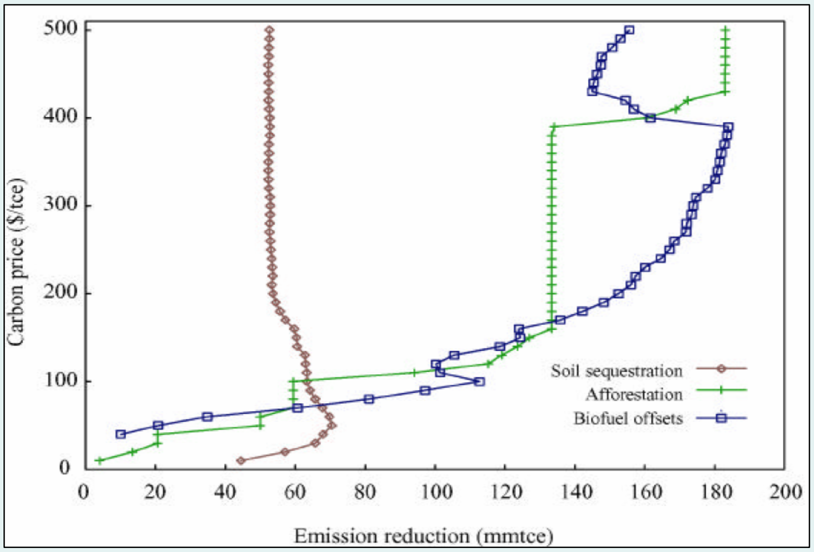
- Ancillary impacts are non-GHG related effects of a mitigation project.
    1. Note that mitigation project revenues (which are an ancillary benefit) are addressed in Section 5.8.2.
- Ancillary impacts are often difficult to quantify.
- A scaled-down Environmental Impact Assessment (EIA) methodology is a recommended format for organizing a qualitative analysis of prospective projects that will assist decision-makers.
- Utilities should not implement or invest in projects with significant negative ancillary impacts.

5.8. Cost per ton of carbon equivalent

- **Criteria:** *The cost per ton value for implementing a mitigation option is within the desired cost range.*

The criteria of top priority and greatest familiarity to a municipal utility are economic considerations related to project implementation, since project decision-making and planning rely heavily on both project cost and return-on-investment (ROI) calculations. The most basic tool used to assess GHG mitigation projects is to compare estimates of the cost per ton (CPT) of mitigated GHGs. This tool was initially developed to analyze reduction activities for criteria pollutants, such as NO_x and SO_x, and it has become the standard for GHG mitigation analysis. Key CPT considerations are presented in Box 5.8.

Figure 5.8. Cost abatement curves for three strategies. (Source: Schneider, 2001)



CPT estimates usually have to be qualified by the number of tons to be mitigated as well as by the period of mitigation. For example, the CPT to mitigate an initial 100 tons of a GHG might only cost $10 per MTCE, but the cost could increase to $20 per ton to mitigate an additional 100 tons. Conversely, economies of scale may apply to certain options, resulting in a reduced CPT with incremental increases in tons mitigated. The cost abatement curve presented as Figure

5.8, is the graphical representation of these relationships between amount of GHGs mitigated and CPT. The data refer to a national emissions reduction policy, and not to a specific entity. The most cost-effective strategy is contingent upon the carbon price. For instance, if the carbon price is $50 per ton, soil sequestration can reduce emissions by ~70 MMTCE compared to 50 MMTCE for afforestation and 30 MMTCE for biofuel offsets. At a higher carbon price of $200, biofuel offsets can reduce emissions by more than 150 MMTCE, compared to 130 MMTCE achieved by afforestation and 55 MMTCE achieved by soil sequestration, previously the most cost-effective option at $50 per ton.

The CPT calculation can be made up of multiple figures. The numerator, US dollars, is often expressed as total costs, marginal costs, or average costs. The sequestration amounts can be expressed as occurring over one year, the project life, or discounted to the present value. This creates a total of nine CPT calculations, of which a comparison is difficult to make (Richards, 2004). While there is no standard calculation, the use of marginal costs[4] over an annual period is more useful than other calculations when comparing mitigation options (Richards, 2004).

5.8.1. Calculating Cost per Ton (CPT)

Total costs in the CPT calculation are the sum of working capital, operation and maintenance (O&M), and disposal costs. The total costs are then divided by the amount of GHGs mitigated in metric tons of carbon equivalents (MTCE) to come up with the CPT.

Working capital costs are the current assets that are required for the startup and support of operational activities (Sullivan, 2003). These costs can include any expenses incurred from project design to the point at which the project is operational. *Startup costs* would include any expenses incurred after the completion of construction until O&M costs are incurred. *Disposal costs* are non-repeating costs of shutting down the operation and the retirement of assets at the end of the project (Sullivan, 2003). These can include costs associated with a land-use change at the end of an agricultural sequestration project, decommissioning of equipment from a geological sequestration or landfill methane project.

For example, utilities involved in forestry sequestration can collaborate and share working capital expenses. PowerTree Carbon Company, a consortium that includes large utilities like American Electric Power, has started a reforestation project in the South of the U.S. that will sequester more than 325,000 tons at a working capital cost of $3.4 million, or about $10 per ton. O&M costs, usually much lower than working capital costs, are excluded from this total.

The working capital costs for a reforesting project may include soil preparation and tree purchase and planting. After the construction is complete, startup costs would include any expenses incurred up until the project begins to sequester GHGs.

Operation and maintenance costs are repeating, annual expenses associated with the operational phase of a project (Sullivan, 2003). The O&M costs for agricultural and forestry sequestration will mainly consist of quantification, monitoring, and verification costs that can be further separated into initial costs, annual fixed costs, and annual variable costs. These costs are usually one or two orders of magnitude less than working capital and startup costs. Cacho (2004) has estimated O&M costs to be between $0.45 and $2.11 per TCE. The variability in estimates is due to spatial considerations, monitoring type, and discount rates (Cacho, 2004).

[4] Marginal cost is the additional cost of producing just one more ("marginal") unit of output.

5.8.2. Return on Investment (ROI)

ROI is generally considered to be **the amount of profit realized from an investment**. The potential for returns on investment (ROI) on some types of mitigation projects can drastically affect cost per ton estimates, resulting in ancillary financial gains. For example, landfills or farms that produce methane could capture and use the gas for electricity or heat, instead of releasing it or flaring it. Hundreds of landfills around the country that already do this and the EPA has compiled a database of potential methane-capturing landfills. Another possible revenue source is enhanced oil recovery during geological sequestration projects. For at least 20 years, oil companies like ChevronTexaco have been injecting natural CO_2 into oil reservoirs to increase pressure in the reservoir and, in turn, increase the amount of oil that can be recovered (Chevron, 2004). If emitted CO_2 was used instead, they might gain revenues from both emissions credits and enhanced oil recovery operations.

In addition, if market-based GHG mitigation regulations were to be instituted, the most likely sources of revenue from GHG mitigation projects would be GHG reduction credits. These would come about as a result of a GHG emissions trading program where emissions are capped and sources are allowed to trade with each other. Trading programs could also include third parties who, in addition to sources, develop projects to mitigate GHGs.

An emissions trading program would set a price for carbon. The price of carbon is analogous to the amount of money needed to reduce or sequester one ton of carbon dioxide or another GHG. The price of carbon would vary by market, but would eventually correlate with the value of an emissions credit. A company could either spend $10 per ton to change their operations and reduce their emissions by 1 ton, or they could buy an emissions credit on the market for $10.

> **The Chicago Climate Exchange (CCX) has created an exchange for carbon trading, where the price as of March 2005 is about $1.65 per metric ton of CO_2 (about $6 per metric ton of C), an increase of nearly $1 from earlier in the year. The EU ETS also has a carbon trading market, where as of March 1, the price is about $11 per metric ton of CO_2 or about $40 per metric ton of C – it is higher due to the EU's mandatory reduction requirements.**

The use of CPT (and ROI) estimates to compare mitigation strategies is a fairly straightforward process. However, it is often difficult (if not impossible) to calculate precise values for generic mitigation options, as many values that need to be included in CPT calculations are very project-specific. Therefore a **range of costs** that were gleaned from scientific literature and other publications is presented in Table 8.2 to help provide a general comparison of mitigation options based on cost. ROI values are included for some, but not all, mitigation strategies.

Box 5.8. Cost per ton (CPT)

- CPT is cost per ton of carbon kept out of, or removed from, the atmosphere.
- CPT estimates in this guide are presented in terms of carbon equivalents.
  - 10 metric tons of CO_2 = 2.727 metric tons of carbon.
  - $10 per ton of CO_2 mitigated = $10 per 0.27 tons of carbon mitigated.
- CPT should be the sum of working capital, operation and maintenance (O&M) and disposal costs, divided by the amount of GHGs mitigated.
- Since most available CPT estimates do not include certain project costs (such as QMV), example values are often underestimating the actual CPT for a project.
- The marginal CPT over an annual period is the most useful figure when comparing mitigation options.
- Utilities should use CPT estimates for evaluating mitigation options in two ways:

1. As an order of magnitude estimate of likely project costs.
2. To compare the relative expected costs of different approaches to GHG mitigation.

- A few of the mitigation strategies under consideration address emissions of other GHGs to the atmosphere. This guide uses the global warming potential conversion rates suggested by the U.S. Environmental Protection Agency standards (EPA, 2004).
  - The GWP of 1 metric ton of CH_4 = the GWP of 21 metric tons of CO_2. Tons of CO_2 are then translated into carbon equivalents as described above.
- Many CPT estimates already include potential ROI values.
- Certain mitigation alternatives such as energy efficiency and process modifications may yield instant ROI results through cost savings and improved plant efficiency.
- In the event of the creation of an emissions trading program, offsets created in excess of a utilities' target goals are a potential source of revenue.

5.9. Regulatory acceptance

- **Criteria:** *A mitigation option will most likely be accepted under future regulations and/or are accepted under existing government-legislated voluntary programs.*

In choosing among mitigation options, utilities lack guidance in the form of mandated GHG emissions regulations. However, they can still make relatively informed decisions with respect to future regulatory acceptance by considering the goals and frameworks of the Kyoto Protocol, U.S. national and state voluntary GHG mitigation programs (e.g. DOE 1605b), and proposed legislation for mandatory measures, as well as existing air pollution regulations under the U.S. Clean Air Act (CAA) of 1970 and CAA Amendments of 1977 and 1990. A review of accepted mitigation options (under climate change programs) and overall regulatory criteria of the CAA provides valuable insights, because regulation and rule development tends to follow existing policies and regulations that have proven acceptability and effectiveness (Rabe, 2002).

Table 5.9. Evaluative criteria for emission reduction credit potentials as outlined in EPA Guidance documents for emissions reduction measures *for criteria pollutants*.

Criterion	Description	Attributes addressed by Criterion
Quantifiable	• Emission reductions must be quantifiable. • Procedures must exist to evaluate and verify that reductions achieved over time remain at reported levels. • U.S.EPA issues guidance documents with emission quantification methods for accepted criteria pollutant reduction approaches. • When guidance is not available, U.S.EPA considers alternative protocols. Without federal recognition of GHGs as pollutants, GHG mitigation approaches would be considered under the criteria pollutant framework for assessing alternative protocols	Quantification; verification (Section 5.2)
Surplus	• Reductions that are not otherwise relied on to meet air quality requirements are eligible for offsetting credit. • These reductions must be voluntary and in excess of reductions required by any federal, state, or local law, regulation or order.	Baseline and additionality (Section 5.1)
Enforceable	• Reductions in air pollutants must be enforceable. • Key considerations that relate to GHG mitigation are the requirement for monitoring, recordkeeping and reporting.	Monitoring and verification (Section 5.2)
Permanence	• Reductions must be permanent throughout the term for which a credit is granted. That is, there should be no retransimission of GHGs back into the atmosphere and leakage is to be accounted for. • Credits are seldom voided outright but they can decrease over time. Impermanence results from new emission standards (adopted after the original reduction took place) that require ratcheting down emissions. The value (difference between what is required and what was initially reduced) can be discounted. • Permanence issues with GHG mitigation arise for different reasons, but the result is the same – discounting of offsets/credits.	Permanence (Section 5.3)

Acceptance of a mitigation option under existing voluntary climate change programs and/or proposed legislation provides strong evidence of future regulatory acceptance. Discussions in Chapter 6 and Appendix A describe regulatory acceptance considerations for the mitigation options.

In addition to climate change policy, utilities should consider existing overall regulatory design and compliance criteria and how these might dictate or influence the future regulatory acceptance of an option. Two primary types of environmental regulation exist: (1) economic incentives and (2) command-and-control (Kolstad, 2000). The 1990 CAA Amendments that introduced tradable emission permits (allowances) are an example of economic incentives, whereas New Source Review and the National Ambient Air Quality Standards under the CAA are traditional, command-and-control regulations. Both types have costs and benefits as the implementation of the Clean Air Act of 1970, CAA Amendments of 1977 and 1990, and the California Clean Air Act have demonstrated (Hockenstein et al, 1997, 14). Though much discussion centers on the economic incentive approach, both the Aspen Institute and Pew Center on Global Climate Change conclude that eventual legislation for mandatory GHG reductions will remain the most effective and politically feasible means to regulate if it is partly based on a command-and-control approach (BNA, 2 April 2004).

Under a command-and-control approach, demonstration of an option's viability (to successfully sequester, reduce, or capture GHGs) is essential for regulatory acceptance. For an economic incentives approach, it is the viability of claimed emission reduction credits (ERCs) that needs to be demonstrated for regulatory acceptance. An evaluation of regulatory acceptance is simplified by concentrating on the second, more stringent economic incentive approach.Four primary evaluative criteria (Table 5.9) for credit potentials are outlined in EPA Guidance documents for emission reduction measures (EPA-b, 2004). These four criteria are addressed by the first four GHG mitigation attributes described previously in this section. Combined performance under these attributes serves as a proxy for expected regulatory acceptance (based on existing air pollution regulations).

Box 5.9. Regulatory Acceptance

- Although regulations for mandatory reductions of GHG emissions are lacking, there are a number of government-sponsored voluntary programs that are good benchmarks for acceptable GHG mitigation options.
- The four criteria used in assessing criteria pollutants are very similar to the four core attributes (presented at the beginning of Chapter 5) necessary for good mitigation options to possess.

5.10. Preferences of the utility

- **Criteria:** *Mitigation options chosen are consistent with a utility's philosophy and/or mitigation goals.*

As discussed in the previous section, mitigation plans should focus on options that have a high probability of regulatory acceptance. However, the decision process should also incorporate utility-specific considerations or preferences, while being sensitive to the regulatory future. Preference considerations for the option selection process are described below. A non-exhaustive list of questions (Box 5.11.a and Box 5.11.b) accompanies each consideration to facilitate analysis.

5.10.1. Mitigation preferences

Economic, environmental and methodological analyses of mitigation options will take into account objective attributes. However, a utility's option selection may be based on other subjective considerations. These might be aligned with the philosophy or goals of the specific business. For example, a business plan defines the organization and its goals. It is designed to allocate resources efficiently and to facilitate short-term business decisions while maintaining focus on the overarching long-term objective(s). Real and/or perceived deviations from a business plan may be viewed as unwise. For example, a utility may view an international forestation project as moving outside the philosophy of investment in national interests and business. Instead, they may opt for a mitigate option that will retain funds within the United States.

Box 5.10.a. Mitigation Preferences

- Answers to the following questions help to determine the mitigation preferences of a utility:

1. Is there an option or set of options that fit within the Business Plan?
2. Are there ancillary benefits derived from the mitigation approach that can be easily capitalized upon given the scope of the business plan?
3. What are the sunk costs to the organization for each option if it needed to be abandoned?
4. If abandoned, are there secondary benefits that can be capitalized on (e.g., selling the equipment, change the end use of the equipment, use of the land)?

5.10.2. *Costs and benefits to stakeholders*

Stakeholders are the entities that have vested interest in the activities of the utility. For this discussion, the Board of Directors represents the interest of all stakeholders.

Decision-making at the Board of Directors level can provide challenges to, as well as assistance with, getting approval for GHG mitigation projects. The Board's accountability to the public is a potentially significant hurdle for decision-making in terms of the current economic and regulatory uncertainties of GHG mitigation. Additionally, in establishing policies for insuring the organization's future financial stability, the Board might not facilitate the consideration of GHG mitigation projects (e.g. by not allocating funds for this purpose). Conversely, one of the major responsibilities of a Board of Directors is to enhance the organization's public image. This may provide a justification mechanism upon which to seek project approval.

Box 5.10.b. Costs and Benefits to Stakeholders

- In considering project options, utilities should use the following question to identify concerns of their stakeholders who are represented by the Board of Directors.

1. Are there Policies that will prevent the Board from adopting a mitigation project?
2. Are there short- or long-term goals of the organization that prevent Board adoption of a mitigation project?
3. What risks are posed by the mitigation approach that could be returned as a liability?
4. Is there sufficient uncertainty with the project that the Board will be hesitant to approve its implementation?
5. Will the project be perceived by the public as a positive endeavor?
6. Is there sufficient analysis of all possible options to assist the Board in the decision-making process?
7. Are there additional steps that can be taken to reduce uncertainty prior to Board review?

5.11. Existing relationships

- **Criteria:** *Implementation of a mitigation option can take advantage of existing business relationships with other organizations .*

Another decision factor, summarized in Box 5.12, may be the existence of business relationships that provide advantages (i.e. can be leveraged) for mitigating GHG emissions. For a utility, this might take the form of taking advantage of existing business relationships with other utilities (e.g. such as utilities that are part of the Southern California Power Producers Authority) or partaking of investment opportunities for projects that are implemented at another facility due to lower marginal costs. For example, a relatively large coal-powered facility located near a viable geological sequestration reservoir may have the technology to implement an injection approach at a lower cost per ton than a smaller utility that has only limited resources available for mitigating their own emissions.

Box 5.11. Existing Relationships

- Small municipal utilities should look to their existing business relationships for opportunities to implement different types of mitigation projects at lower costs.
- Projects that need to be implemented on a large scale are more feasible choices if a small, municipal utility takes advantage of joining with other organizations to finance the project.
- Factors that will affect the nature of these opportunities include:

1. The mutual benefits of entering into an agreement.
2. The timeframes required of the relationship in order for benefits to be sufficiently realized.
3. The likelihood of straining existing relationships by pursuing a mitigation project.

5.12. Perception of public

- **Criteria:** *There is wide public acceptance of a mitigation option.*

Currently, utilities are facing public scrutiny since the energy sector has been identified as the largest contributor of GHG emissions in the industrialized world (Wilson, 1993). In light of such attention, they are sensitive to their public image. GHG mitigation options may face the same public scrutiny for lack of proven effectiveness or public and environmental safety. Currently, non-governmental organizations are expressing concern over what they view as emerging social injustices with regards to forest sequestration projects and carbon trading schemes involving developing nations' forests (TNI, 2004). Additionally, there is scientific uncertainty as to possible inducement of seismic activity resulting from geological sequestration (White, et al, 2003).

The questions in Box 5.12 address these public perception issues. It is important to remember that most options will be met with at least some resistance from the public.

Box 5.12. Public Perception

- In considering project options, utilities should use the following question to identify how an option might be perceived by the public.

1. Are there sufficient enough uncertainty and/or risk of realizing benefits that public perception is a key consideration?
2. Are non-governmental organizations lobbying against the mitigation approaches?
3. What degree of government funding is involved with the mitigation option?
4. How much "exposure" to public scrutiny and/or disfavor is acceptable?
5. How compelling (potentially inflammatory) are arguments directed against the mitigation approach?

FOR FURTHER INFORMATION ON:

- **Baseline and additionality**

Overview of GHG accounting

- Acharya, M. (2003). The Greenhouse Gas Protocol: Accounting for Project-based Greenhouse Gas Reductions. Geneva, Switzerland: World Business Council for Sustainable Development. http://www.ghgprotocol.org/docs/GHG_PM_EarthTech03Paper.pdf

"GHG Protocol Project Quantification Standard – Road Test and Review Draft," the recommended protocol for project accounting procedures: baseline, additionality and quantification

- Ranganatha, J., Greenhalgh, S., Corbier, L., Acharya, M. (2003). GHG Protocol Project Quantification Standard – Road Test and Review Draft. Washington, D.C.: World Resources Insitute; Geneva, Switzerland: World Business Council for Sustainable Development. http://www.ghgprotocol.org/resources_and_documentation/projectmodule.htm

- **Quantification, monitoring and verification**

Overview of GHG accounting

- Acharya, M. (2003). The Greenhouse Gas Protocol: Accounting for Project-based Greenhouse Gas Reductions. Geneva, Switzerland: World Business Council for Sustainable Development. http://www.ghgprotocol.org/docs/GHG_PM_EarthTech03Paper.pdf

In-depth discussion of monitoring and verification of GHG mitigation projects

- Ellis, J. (2002). Developing guidance on monitoring and project boundaries for greenhouse gas projects. Paris, France: Organisation for Economic Co-operation and Development, International Energy Agency. Information Paper: COM/ENV/EPOC/IEA/SLT(2002)2. http://www.oecd.org/dataoecd/44/50/2757386.pdf

Examples of how to quantify the GHG abatement achieved by different types of mitigation projects

- Wisconsin Department of Natural Resources (June 2003). "Quantification Examples." Air Management Program. Wisconsin Department of Natural Resources website: http://www.dnr.state.wi.us/org/aw/air/registry/quantexamples.html

➢ Permanence and Leakage

Overview of permanence and leakage

- Murray, B.C. (12-15 October 2004). Addressing permanence and leakage of GHG benefits from forest and agricultural projects. (Presentation). Third Forestry and Agriculture Greenhouse Gas Modeling Forum. Shepherdstown, WV. http://foragforum.rti.org/papers/index.cfm

➢ Ancillary impacts

Overview of ancillary impacts of GHG mitigation

- Davis, D.V., Krupnick, A., McGlynn, G. (2000). Ancillary benefits and costs of greenhouse gas mitigation: An overview. Organisation for Economic Co-operation and Development, Paris. http://www.oecd.org/dataoecd/0/12/1916721.pdf <12 February 2005

➢ U.S. Regulatory Policy on Greenhouse Gas Mitigation

The Pew Center has done an extensive review of various policy aspects of climate change including what businesses, state, regional, and national governments, and academic researchers have done to address greenhouse gas control, reduction, and mitigation.

- Pew Center on global Climate Change
  2101 Wilson Blvd, Suite 550
  Arlington, VA 22201
  Tel: (703) 516-4146
  http://www.pewclimate.org

The West Coast Governor's Global Warming Initiative is a reference source for policy and standards guidance from California, Oregon, and Washington state governments.

- West Coast Governor's Global Warming Initiative
  http://www.energy.ca.gov/global_climate_change/westcoastgov

6. Mitigation Options

A broad range of GHG mitigation options exist, including reduction, **sequestration**, and **capture/use**, (Table 6). These options are at various stages of maturity. Whether a utility plans to initiate its own mitigation project or invest in an existing program (e.g. a consortium or credits from a trading program), it is essential to become familiar with the options available before beginning the decision-making process. This section introduces these mitigation options and presents key recommendations for small municipal utilities. *Cost estimates presented in this section have 2005 cost adjustments in parentheses.*

While reviewing the list of mitigation options in Table 6, consider the following points:

- Some of the mitigation options in Table 6 are very broad, incorporating multiple sub-categories;
- This list is dynamic; technology and regulatory developments may add new categories and shift the way in which an approach to mitigation is categorized; and
- Although from Table 6 it appears that the options are exclusive, some represent combinations of different approaches.

Table 6. List of options and their mitigation classification.

Reduction	Sequestration	Capture/Use
Industrial process modifications Section 6.1.1	**Forest sequestration** Section 6.2.1	**Methane capture** Section 6.3.1
Renewable energy transitions Section 6.1.2	**Agricultural sequestration** Section 6.2.2	**Biomass to energy** Section 6.3.2
Demand Side Efficiency improvements Section 6.1.3	**CO_2 injection into geological formations** Section 6.2.4	**Biomass to product** Section 6.3.3
	Mineral carbonation Section 6.2.5	
	Ocean Sequestration (injection; seeding) Section 6.2.6	

6.1. Reduction Options

Reduction options involve avoiding or substituting for GHG-producing activities.

6.1.1. Industrial process modifications

Two sub-categories under industrial process modifications are considered in this guide.

Fuel switching

In the utility sector, fuel switching from high- to low-carbon content fuels can be a relatively cost effective means to mitigate GHG emissions because it also improves combustion efficiency and reduces quantities of criteria pollutants. Additionally, technologies such as Briquette coal (Zhang et al., 2001) and Carbon Burn-Out (ENSR, 2003) are used in coal-fired utilities to minimize the generation of regulated criteria pollutants. This pre-combustion approach requires few, if any hardware changes to a facility (as opposed to the second approach described below), and therefore has lower capital costs.

Reductions of 10-20% in CO_2 emissions are possible by applying fuel switching to manufacturing sectors such as the iron and steel, cement and chemical industries. (IPCC, 2001c). As an investment strategy by a utility, there is some question as to the opportunities present for cost effectively switching fuels. Fuel choice is often industry sector specific and thus, cost effective alternatives are greatly limited or nonexistent (IPCC, 2001). However, specific opportunities exist to replace coal-fired boilers with natural gas-fired combined heat and power (CHP) turbines; to use natural gas-derived steam in ammonia production; and to fire blast furnaces with natural gas rather than coal.

For example, briquette coal as a replacement fuel results in fuel cost increases of 9 to 16%, though these costs are offset by an estimated 26% reduction in CO_2 emissions, increased fuel efficiency, and decreases in criteria pollutant emissions (Zhang et al., 2001); cost per ton (CPT) is dependent on variable fuel costs and therefore not estimated. Carbon Burn-Out is estimated to save less than 1.5% of fuel costs with remaining capital and operating cost offsets of the technology derived from avoided landfill costs and selling of the ash. Realized carbon reduction credits are derived from ash replacing the production of Portland Cement, estimated at 144,000 tons CO_2/year (ENSR, 2003). CPT of technologies such as Carbon Burn-Out has not been estimated due to variability of costs such as landfill disposal, carbon credits, and Portland Cement manufacturing.

Efficiency improvements (industrial)

Changes to conventional combustion technologies have the potential to improve their energy efficiencies. The national average thermal efficiency for conventional combustion is 32-33% (DOE, 2000). By utilizing unused waste heat for electricity generation, efficiencies of 45-55% can be attained (White, 2003). According to DOE, combined heat and power (CHP) and combined-cycle (CC) upgrade projects were a major contributor to GHG reductions from 1998 to 1999 (DOE, 2000). Technologies such as natural gas combined cycle (NGCC) and combined cycle gas turbines (CCGT) improve combustion efficiencies and provide proportionately favorable reductions of GHG and criteria pollutant emissions; for a 1% in efficiency, GHG reductions of 2.5% of previous levels are possible (White, 2003). The integrated gasification combined cycle (IGCC) technology goes a step further by reducing costs associated with capture and separation of CO_2 from exhaust streams (White, 2003).

Issues with these industrial process modifications include the initial capital costs (relative to the life of a process) and increased operating and fueling costs. These expenses might be offset by the combined benefits of improved efficiencies, reductions in pollutants (both GHG and criteria), and generated emission reduction credits. As a result of these combined benefits, Mills et al. (1991) suggest that there is no net cost and further suggests that realized net *benefits* for theses technologies range from $100 to $313 per TCE avoided. Though substantial evidence exists that industrial modifications provide benefits to GHG mitigation, criteria pollutant mitigation, and operational cost reductions, current environmental legislation hinders the adoption of the this technology (Prindle, et al., 2003). Air quality regulations determine a facility's emission allowances on fuel input rather than power output, thereby discouraging thermal efficiency system upgrades. However, the EPA has provided a guidance document for energy efficiency (EPA, 2004) that addresses CHP and CC upgrades and many states are beginning to address regulatory barriers to thermal efficiency upgrades (Prindle, et al., 2003).

Another source of energy efficiency investment can be realized in the industrial sector. The manufacturing industry sector is a prime candidate for energy efficiency through reductions of direct fossil fuel usage as well as indirect usage (electricity), both accomplished by a number of technology upgrades (IPCC, Working Group III: Mitigation, 2001). In general and applicable to all industries, process control and energy management systems can better control combustion efficiencies and fuel feed rates; cogeneration systems can utilize waste heat as an additional energy source; and high efficiency, low friction motors and drive systems improve the overall efficiency of generated energy converted to work. In addition to these general categories, individual manufacturing industries have opportunities for energy efficiency improvements as well. Specific industrial sectors with high potential for GHG mitigation includes cement manufacturing, metals production, refineries, pulp and paper mills and chemical manufacturing (IPCC, 2001).

Summary of Key Considerations for Industrial Process Modifications:

- Regardless of mitigation benefits, industrial energy efficiency efforts have "no-regret" payoffs in the form of reduced criteria pollutant emissions and decreases in fuel use costs.
- Volatility in fossil fuel prices increases the difficulty in implementing a fuel switching strategy from high- to low-carbon intensity.
- California utilities should petition policy makers to exempt energy efficiency upgrade projects from current regulatory measures that dis-incentivize such projects.
- California utilities should support output-based regulations as a measure of GHG emission inventories and reduction projects as low carbon-intensive fuel use biases emission rates and reduction potential to higher carbon-intensive fuel usage.

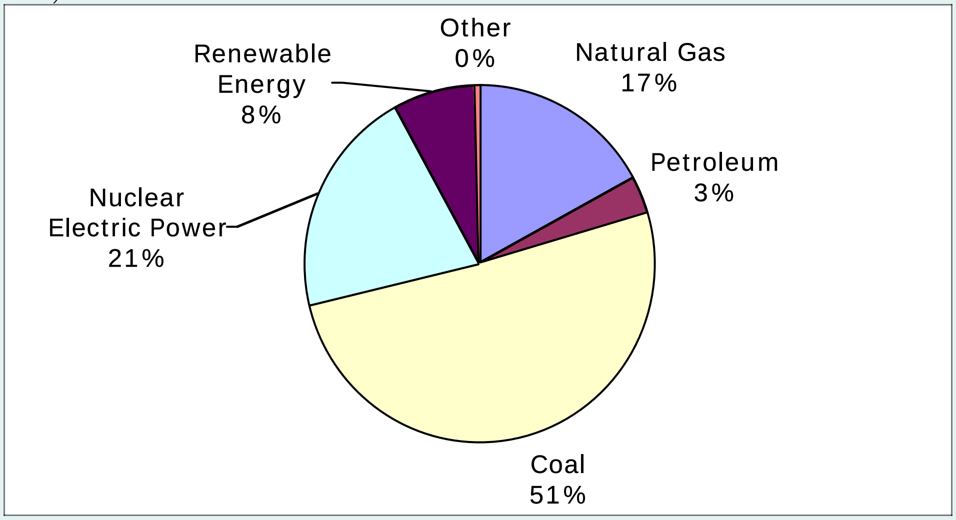
6.1.2. Renewable energy transitions

Non-renewable, carbon-based fuels provide most of the energy used for electricity and heat service, and transportation. As a result they are the leading cause of anthropogenic emissions of CO_2 to the atmosphere. Renewable energy is a growing option for utilities and their customers to reduce or eliminate GHG emissions by replacing the fossil fuel-based energy uses.

For policy purposes, a distinction must be made between renewable energy and clean energy, both of which produce no GHG emissions. Renewable energy is from an energy resource that is replaced rapidly by a natural, ongoing process. Under this definition, neither fossil fuels nor nuclear power are renewable. Clean energy encompasses both renewable energy and energy that requires the use of substances that are non-renewable or produces other non-GHG waste byproducts, such as nuclear energy. Nuclear energy is excluded from this guide as a mitigation option, because of its high working capital costs and waste containment impacts on the environment. Hydrogen and fuel cells (types of clean energy) are also excluded from this analysis because hydrogen production is a GHG-emissions-intensive process, even though the combustion of hydrogen is not and because the technology is still in a developmental phase.

Figure 6.3.2.a. shows a breakdown of fuel type for electric power generation in the US in 2001. Carbon-based fuels make up 71% of total electric power generation, leading to nearly 3.85 Gt of annual CO_2 emissions. Renewable energy makes up 8% of the total, while nuclear energy, at 21% makes up the remainder. The Energy Information Administration (EIA)'s forecast for 2025 increases renewable energy's share of the total to only 9%, while carbon-based fuels make up 76% of the total (DOE, 2005h). This forecast does take into account the various state Renewable Portfolio Standard (RPS) programs that are currently being implemented (discussed later in the text).

Figure 6.1.2.a. Primary energy consumption by fuel type. (Source: DOE, 2001).



Renewable energy types

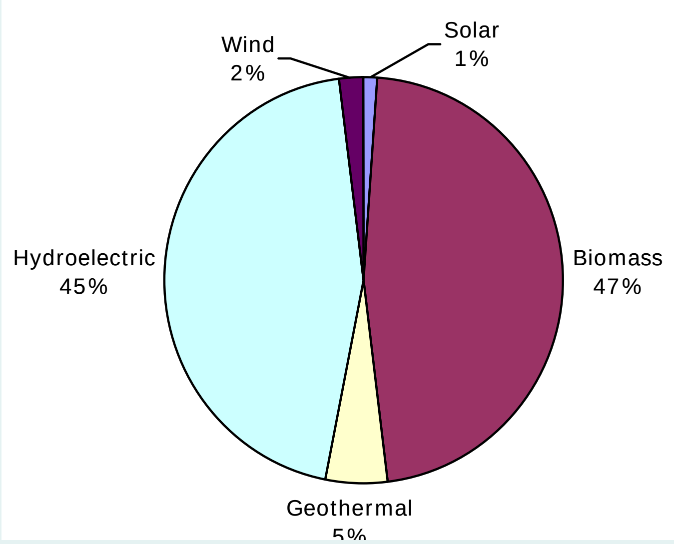
Both California and Texas are among the leaders in state renewable energy policy. The Texas Renewable Energies Industry Association and Texas legislature define renewable energy as "…any energy resource naturally generated over a short time scale and derived directly from the sun (such as thermal, photochemical, photoelectric), indirectly from the sun (such as wind, hydropower, and photosynthetic energy stored in biomass), or from other natural movements and mechanisms of the environment (such as geothermal and tidal energy). Renewable energy does not include energy resources derived from fossil fuels, waste products from fossil sources, or wastes from inorganic sources." The Department of Energy (DOE)'s Office of Energy Efficiency and Renewable Energy (EERE) has similar definitions of renewable energy and classifies it into the following categories:

- Biomass Program
- Geothermal Technologies Program
- Hydrogen, Fuel Cells and Infrastructure Technologies
- Solar Energy Technologies Program
- Wind and Hydropower Technologies Program

Figure 6.1.2.b below shows the share of renewable energy consumption by fuel in the US in 2002. While wind provides only 2% of the US's renewable energy consumption, it is the fastest growing form of

renewable energy. The use of wind energy grew by 242% from 1998 to 2002, while non-wind renewable energy declined by 10%. (DOE, 2003g).

Figure 6.1.2.b. Renewable energy consumption by fuel type. (Source: DOE, 2002).



Biomass energy is the use of renewable resources such as agriculture and forestry products and residues, municipal solid waste, and landfill gas. While carbon is released when biomass fuels are burned, this is offset by the carbon that is stored in biomass fuel sources. Since this process is part of the natural carbon cycle, the emissions are theoretically zero. Total electric power generation from biomass in the U.S. is 9,733 MW (DOE, 2005). This mitigation approach is discussed in greater detail in sections 6.3.1 and 6.3.2. Section 6.3.1 describes capture and use approaches for methane and 6.3.2 discusses biomass to energy approaches.

Geothermal energy is created using underground steam to power turbines and electric generators. There are three types of geothermal power plants – dry steam, flash, and binary cycle. The DOE is anticipating that geothermal capacity will increase to 15,000 MW over the next ten years, and that most will involve binary cycle systems. The DOE is also working with the industry to bring costs down to \$0.03 - \$0.05 per kWh (DOE, 2005). Emissions from geothermal plants are not zero, but are much lower than emissions from coal-fired and natural gas-fired plants. Geothermal plants emit an estimated at 27 kg Carbon per MWh, compared to 386 kg C per MWh for new natural gas plants (DOE, 2005).

The geothermal potential in California is estimated at greater than 5,000 MW (CEC, 2004). The California Energy Commission (CEC) has provided technical and financial assistance for geothermal projects since 1981. San Bernardino, in San Bernardino County, has one of the largest geothermal energy systems in the world that provide electricity to more than 20 buildings, including the City Hall and the City Detention Center (CEC, 2005). The average payback period for this project by customer was 2-3 years. The city of Susanville, in Lassen County, also uses geothermal power to provide electricity to 30 residential and commercial buildings (CEC, 2005).

Solar power uses the sun's heat energy and sunlight to provide electricity and heating. Solar power can be used in concentrated solar power, photovoltaics, solar heating and solar lighting systems. The DOE has established the Million Solar Roofs program, to install solar systems on one million buildings by 2010. The program looks to bring together public and private interests to build a solar market. Governor Schwarzenegger has also advocated for state legislation requiring that a certain percentage of new homes have photovoltaic systems. BWP, like other municipal utilities, already has rebate programs for residential and commercial customers that purchase solar power installations.

Hydroelectric power utilizes the potential energy in flowing water to turn a turbine and generate electricity. It is the US's largest source of renewable energy, and is more commonly used in northern California than southern California. The CA Renewable Portfolio Standards (RPS) only include existing hydroelectric power sources that are less than 30 MW. In addition, the RPS only allows new hydroelectric power sources if they do not result in new or increased water appropriations (REPP, 2004).

Wind energy is captured by turbines that transform wind to electricity. Four of the five major wind farms in California supply electricity to the two largest Investor Owned Utilities (IOUs) – PG&E and Southern California Edison (AWEA, 2005). The other major wind farm supplies electricity to Sacramento Municipal Utility District. The CEC has classified wind along with solar power as emerging technologies and established a program to provide purchasers with subsidies. These subsidies provide between $1.70 and $3.20 per watt for wind, solar thermal, photovoltaic (PV), and fuel cell (using renewable fuels) installations less than 30 kW, for customers within the IOU's service areas. As costs decreased, capacity has increased at an annual rate of 20% (AWEA, 2005). Research and development related to wind energy will also become more important in the future, as turbines become larger and more efficient. The DOE and the American Wind Energy Association (AWEA) have set a goal that wind energy provides 100 GW of capacity or 6% of total energy supply by 2020.

State Renewable Portfolio Standards

Part of the reason for the growth in the renewable energy sector is due to the development of Renewable Portfolio Standards (RPS). In the absence of federal action, states are beginning to mandate increases in renewable energy generation as part of a power supplier's energy mix. Through the end of 2003, 12 states had RPS or legislation that requires renewable energy to make up a certain percentage of the state's total electricity supply. Three other states have set voluntary goals for renewable energy capacity and four other states have pending renewable energy programs.

The use of renewable energy as a GHG mitigation approach will likely coincide with changes to California's current RPS. Municipal utilities will be able to earn carbon credits at the same time as meeting RPS mandates. Currently, an RPS is only required for the state's three IOUs. The current RPS requires that each of the three IOUs generate or purchase 20% of their total electricity supply from renewable sources by 2017. Governor Schwarzenegger's veto of SB 1478, which would have moved the deadline up to 2010, was partly motivated by the lack of capturing municipalities in the proposed RPS. This is suggestive of the interest California has in mandating the same standards that currently govern only IOUs for municipalities (San Martin, 19 January 2005). The governor has advocated that future legislation require a 33% standard by 2020 (UCS, 2005).

A 1997 study by the Union of Concerned Scientists and Energy Innovations showed that a renewable energy target of 10% would result in a price of $95 (equal to $113 per ton in 2005 dollars) per ton of C (UCS, 2005). The capital to pay for renewable energy development would come from a sales tax on electricity. The DOE found similar results through a target of 10% renewable energy generation. The DOE estimated that between 40,000 and 80,000 MW could be generated for a price of less than $50 ($60 in 2005 dollars) per ton of C. (UCS, 2005). Additional cost information relating to municipal utilities is included in the discussion section.

The major environmental consideration of energy generation processes is emissions. Emissions from non-renewable energy systems include GHGs, mainly CO_2, as well as criteria pollutants, such as NO_x and SO_x. Emissions from renewable systems, with the exception of biomass, are virtually zero, and usually only result during the construction of a system. Concerns over the environmental effects of renewable energy usually regard siting, threats to habitat, and waste from the construction of renewable energy systems.

Siting is usually an issue with wind turbines, whose size can be more than 400 feet in height. Turbines need to be spaced a certain distance apart, which can create large land requirements for large wind projects. This is one of the reasons for farmland becoming a more popular site for wind energy installations (UCS, 2004). Farmers can benefit by renting their land, or by installing their own turbines and selling the electricity. For example, siting and threats to habitat are two main objections for a geothermal plant in CA's Medicine Lake Highlands area (SFGate, 2004).

Siting requirements vary by renewable technology type. Despite wind turbines' large size, they are the most efficient users of land among renewable technologies (IEA, 1998). Their land to energy ratio is 0.06 hectares per GWh per year (IEA, 1998). This compares to solar power, whose ratio ranges from 0.25 hectares per GWh per year for solar thermal electric to 1.06 hectares per GWh per year for solar photovoltaic (IEA, 1998).

Summary of Key Considerations for Renewable Energy Transitions:

- Renewable energy transitions are a way for utilities and individual customers to reduce criteria pollutant emissions and decrease fuel use costs, in conjunction with GHG mitigation benefits.

- High capital costs discourage the use of renewable energy for municipal utility-scale applications. However, CA will most likely amend its RPS program to include munis, and provide funding through a public good surcharge. This, along with existing incentive offered by utilities, should lead to renewable energy growth.

- Cooperation between BWP and other munis in purchasing fossil fuel-based electric power can continue for renewable energy. Munis have financing advantages over IOUs, and are eligible for federal renewable energy incentives.

6.1.3. (Demand side) efficiency improvements

Demand side efficiency improvements lead to reduced energy use by residential and business customers receiving distributed services of electricity, gas and water. Utilities' efficiency programs often encourage direct energy use reductions as well as technology enhancements that lead to reductions in energy demands. These options are distinct from efficiency improvements in power generation, distribution, and other industrial processes (described in Section 6.1.1). Assuming that a small municipal utility has relatively little infrastructure that is not related to power generation/distribution or water supply, it should consider implementing the efficiency improvements discussed in this section outside of its own organization (as well as within) to mitigate GHGs.

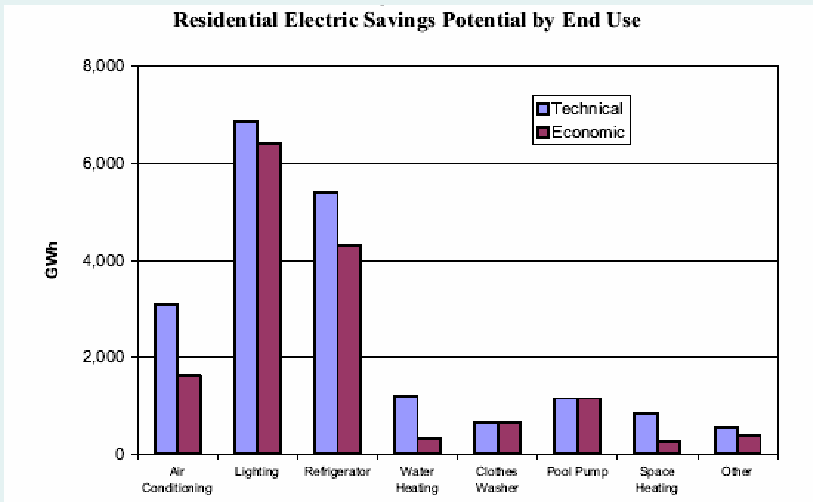
There are already numerous efficiency improvement projects being implemented at both the state and federal level. The federal EnergyStar program promotes the use of energy efficient products in the home and office. Residential energy savings potential for selected home appliances are given in Figure 6.1.3. The EnergyStar program also facilitates technology improvements by creating a strict certification system of energy efficiency for certain products. Efficiency improvements are cornerstone of state energy plans and CO_2 emissions reduction plans (e.g., West Coast Governors' Global Warming Initiative). According to California's 2004 Updated Energy Report, "(the) Energy Commission and CPUC require peak electricity demand reductions of 2,205 MW by 2008 and energy consumption reductions of 10,489 GWh by 2008" (CEC, 2004b).

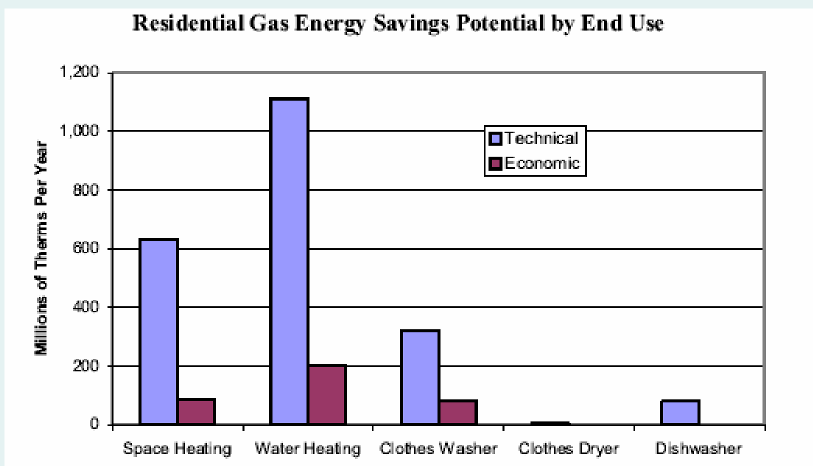
In addition to technological improvements, public outreach and education efforts are also essential for encouraging utilities' customers to reduce their energy consumption. Programs such as California's "Flex Your Power" help achieve these reductions by educating end-users about how and when to best minimize consumption. These types of programs are readily accomplished by municipal utilities because of their close ties to their customer base. In terms of using efficiency improvements as a means to reduce GHG emissions, utilities should leverage existing outreach and education efforts to implement new programs.

In California, utilities play a central role in implementing efficiency improvements by offering their customers incentive programs that are funded by a public benefits charge on electricity bills, which helps to reduce upfront costs of technology upgrades. A California Energy Commission (CEC) study delineated and compared the major options for retrofit applications (Figure 6.1.3).

This figure shows where the potential for energy and cost efficiency are the highest and therefore, where efficiency improvements should primarily be targeted: lighting, air conditioning, and refrigeration for electricity reductions and space and water heating for gas reductions. Many small municipal utilities already manage projects to improve efficiencies of end-user technology (e.g. fluorescent bulb distribution programs) and/or reduce electricity and gas consumption (e.g. funding solar water heating projects for public facilities). In chapter 8, table 8.1.2.b. shows the types of efficiency activities currently being undertaken by BWP.

Figure 6.1.3. Residential energy savings potential by end uses. (Source: CEC 2003b)





The optimal efficiency approaches for a utility depend directly on the characteristics of its customer base. However, almost all utilities seek opportunities to control patterns of electricity consumption to reduce strain on the electrical grid during demand peaks. New technologies are becoming available to facilitate this approach. For example, direct digital control systems at business customer sites incorporate advanced energy efficiency techniques like temperature setbacks based on occupancy, optimized night-time recovery, advanced ventilation control, and occupancy based lighting. Reductions in these demands are especially important from the perspective of abating GHG emissions because the extra electricity is often supplied by peak generators. These generators tend to have relatively poor efficiencies; requiring more fuel for production and resulting in higher associated GHG emissions. As a result, utilities should look for opportunities to reduce peak demand as a way to mitigate GHG emissions.

In general, improved energy savings and GHG mitigation go hand-in-hand. However, using efficiency improvements to create GHG mitigation offsets that will be accepted under a regulatory environment introduces layers of complexity. Most importantly, utilities need to recognize that GHG mitigation benefits of efficiency projects depend entirely upon the type of energy demand that is being reduced. Projects that minimize demand for a *non*-fossil fuel-based energy supply abate little or no GHG emissions.

More specifically, if a utility plans to use an efficiency project to reduce its GHG liability, it will need to go through the process of establishing that the project has additionality. This entails estimating the project baseline emissions. Accurately estimating GHG emissions in the "business as usual" scenario will be especially challenging for projects that involve a large number of customers because numerous projections about future consumptive patterns are required. A utility might also have problems proving that its program will produce a surplus of GHG offsets if efficiency projects rely upon voluntary participation from a large number of customers. Quantification, monitoring and verification of GHG offsets can also be extremely difficult with the dispersed nature of the mitigation; since it is inherently more difficult to track numerous, individual activities. To address this factor, utilities might need to develop customer reporting mechanisms (that are paired with incentives for reporting) to fulfill GHG quantification and monitoring requirements. In general, utilities can avoid some of these problems by planning/selecting efficiency projects that involve one or a few types of customers or technologies with large reductions potentials. For example, a program could target large office buildings for installation of digital lighting and heating control systems and other retrofits that improve efficiencies.

The considerations raised in this section *should not discourage* utilities from implementing efficiency improvements if they have these opportunities. From an environmental perspective, achieved GHG mitigation is fully permanent, and efficiency improvements produce ancillary benefits by conserving natural resources and preventing pollution.[5] Efficiency programs also provide excellent opportunities to develop strong ties with customers and positive perceptions of the utility. Utilities do need to be aware, however, of the challenges to ensuring that their efficiency projects produce GHG offsets that will be acceptable under a future regulatory environment.

Summary of Key Considerations for Efficiency Improvements Options:

- Many municipal utilities are already familiar with implementing approaches to achieve energy savings. As a result, they can leverage this experience to pursue efficiency improvements for GHG mitigation.
- Efficiency approaches provide environmental ancillary benefits and opportunities for positive public relations.
- Generally, energy savings approaches will also accomplish GHG mitigation. However, this might not be the case if reductions in energy usage come from non-fossil fuel-based supplies (e.g. hydropower or nuclear).
- If a utility intends or needs to receive offsets to reduce its GHG liability, efficiency programs will present inherent challenges to establishing project baseline emissions and additionality.
- Quantification, monitoring and verification of achieved GHG offsets from an efficiency project can be challenging if numerous participants are involved.
- Utilities can minimize some of these difficulties by selecting/planning projects that involve fewer customers with large potentials for energy savings.

[5] This latter point about conserving natural resources and preventing pollution applies to all projects that reduce energy consumption– even those that do not mitigate GHGs.

6.2. Sequestration Options

GHG sequestration is the long-term storage of carbon in forests, soils, the ocean and other carbon 'sinks'. In general, carbon sequestration projects can take three forms: forest sequestration, agricultural sequestration, and geological sequestration (Pew Center, n.d.). Sections 6.2.1 and 6.2.2 address forest and agriculture mitigation approaches, respectively. These types of sequestration activities are also referred to as LULUCF (land use, land-use change, and forestry) activities. Section 6.2.3 describes CO_2 capture and separation techniques to provide context for geological storage, mineral carbonation and ocean injection options (Sections 6.2.4- 6.2.6) that require extraction of CO_2 from the exhaust/ waste streams as a preliminary step (White et al., 2003).

6.2.1. Forest sequestration

Terrestrial sequestration activities have the potential to mitigate vast quantities of CO_2. The global potential for forest sequestration is estimated to be between one and five Gt of C per year (Watson, 2000, Grace, 2004). The IPCC estimates 700 Mega hectares (Mha) of forestland is available for sequestration projects world-wide. The capacity for these forests to sequester carbon is approximated at 60-87 gigatons of carbon (GtC) over 50 years, with a maximum carbon uptake rate of 2.2 GtC/yr (IPCC, 2001c).

Forest sequestration occurs through the natural uptake of CO_2 from the atmosphere during photosynthesis as trees grow. Carbon accumulates and becomes stored as woody biomass in the trunk, roots, and limbs of trees. Carbon is also stored in the soil, understory plants and leaf litter (CCAR, 2004). The accumulation rate of carbon depends on a variety of local conditions including temperature, precipitation, slope, exposure, soil texture, and tree species (IPCC, 2000). The carbon content of wood varies both among species and within individuals. According to Mahli et al., carbon content in wood can range from 46.3% - 55.2% by weight. Softwoods (coniferous trees) generally contain 10% more carbon than hardwoods (Mahli et al., 2002).

Forest carbon is stored in four main components (as defined in Birdsey, 1992).

- *Trees:* all aboveground and belowground portions of all live and dead trees, including the bark, trunk (bole), limbs, and roots (greater than 2mm);
- *Soil:* All organic carbon in mineral horizons to a depth of 1 meter excluding coarse tree roots;
- *Forest Litter:* All dead organic matter above the mineral sod horizons including litter humus and coarse woody debris; and
- *Understory Vegetation:* All live vegetation, such as shrubs and herbaceous understory, except that defined as live trees.

Due to the difficulty of accurately quantifying carbon in soils and understory vegetation and litter, estimates of these carbon components are not yet required for forest project inventories.

Although carbon uptake is highly variable between tree species, a growing forest will initially take up carbon at a rapid rate; then as the forest matures and growth slows down, sequestration rates also slow down (Birdsey, 1992). Forest type (categorized by the predominant tree species in a forest) is a big factor regarding the amount of carbon that will be accumulated as woody biomass. For example, Pacific coast forests dominated by douglas fir contain an average of 102 tC/acre (41 tC/ha) compared to 58 tC/acre (23 tC/ha) in an oak-hickory forest (Birdsey, 1992).

The cost range for forest sequestration activities is highly variable. The scope of the project, geographic location, land costs, and forestation and carbon quantification methods used can differ markedly between projects. However, several efforts to account for these differences and compare forest sequestration costs have been made. Richards and Stokes estimate a cost range of $10-$150 MTCE to sequester 250-500 million tons carbon per year in forest plantation and forest management projects (including forest preservation) in the

U.S. and globally. The Pew Center for Climate Change narrows this range down to $7.50-$22.50 MTCE for projects in the U.S. (Richards and Stokes, 2004, Stavins and Richards, 2005).

The types of forestry projects available for GHG mitigation are described below. Figure 6.1.1 estimates the potential of some land management activities for mitigating global CO_2 emissions. The key considerations that an entity should be aware of before embarking on a forestry project are summarized at the end of this section.

Afforestation/Reforestation (Forest Plantations)

Reforestation is the planting of forests on lands that previously contained forests but that have been converted to some other use (IPCC, 2000). Afforestation is the establishment of forests to replace another land use such as cropland or pastureland on lands that historically have not contained forests (DOE, 1994; IPCC, 2000). The IPCC defines reforestation as the planting of forests on land that has not been forested for 50 years or as CCAR defines it, as planting on land that has not been forested for 10 years. Afforestation and reforestation essentially refer to the same activity – regeneration of forests on unforested land. These two activities are also referred to as forest plantation.

Afforestation/reforestation (AR) sequestration potentials for various regions are estimated at 0.4-1.2 tC/ha/yr in boreal regions, 1.5-4.5 tC/ha/yr in temperate regions, and 4-8 tC/ha/yr in tropical regions (IPCC, 2000). As with all forestry projects, these estimates vary widely and are highly dependent on local conditions surrounding the project.

Forest conservation/preservation

Forest conservation/preservation activities differ from other forestry activities in that the GHG mitigation benefit is acquired through the *avoidance of emissions*. Twenty percent of global carbon dioxide emissions are attributed to deforestation activities, illustrating the importance of forest conservation as a global warming mitigation strategy (Vöhringer, 2004). Deforestation is defined as the conversion of forest to non-forest. This includes conversion of forest and grasslands to pasture, cropland or other managed uses (IPCC, 2000).

The protection of existing forests as a way to prevent atmospheric GHG emissions is an accepted form of mitigation under the Kyoto Protocol, except for projects that are carried out under the Clean Development Mechanism during the first commitment period (2008-2012) (Voerhringer, 2004). The CCAR has followed suit and accepts forest conservation projects as a mitigation option so long as the project shows additionality by preventing the conversion of native forests to a non-forest use, such as agriculture or other commercial development (CCAR, 2004). A main cause of concern with forest conservation projects is verifying additionality – would the forest being preserved really have been converted into another land use in the absence of the forest conservation project (DOE, 1994; IPCC, 2001)?

Urban Forestry

Urban forestry activities can augment carbon capture in urban areas through tree growth, and decrease GHG emissions through energy conservation. Trees provide shade that helps reduce air conditioning use, and if strategically planted, can also be used as a windbreak to reduce heating needs during winter months (DOE, 1994). The practice of planting trees in urban settings also provides the added benefit of enhancing urban environments by beautifying the landscape and promoting areas for wildlife. For example, Boulder, Colorado boasts a large urban forest consisting of 330,000 trees city-wide. It has been estimated that these trees sequester over 109,000 Mt of C with an additional 2000 tons annually. This 2000 tons of additional sequestration has been equated to driving approximately 16.1 million miles each year (CBWCO, 2002). However, urban forestry is not widely seen as a GHG mitigation option, especially in areas where the potential for planting large amounts of trees is very low, e.g. CCAR does not currently consider urban forestry as a formal GHG mitigation approach for obtaining GHG offsets.

Other Forestry Practices

The following forestry practices mainly involve augmenting C sequestration by decreasing carbon release during the course of forest operations, such as forest harvest and regeneration and less energy intensive practices. The maintenance of carbon pools is also enhanced by promoting harvesting practices that equal net forest growth (i.e., while timber is being cut, there is always a forest stand that is growing and sequestering CO_2) (Schlamadinger and Marland, 1996). The global potential for sequestration through forest management practices is estimated at 0.17GtC per year (IPCC, 2001b). These practices include:

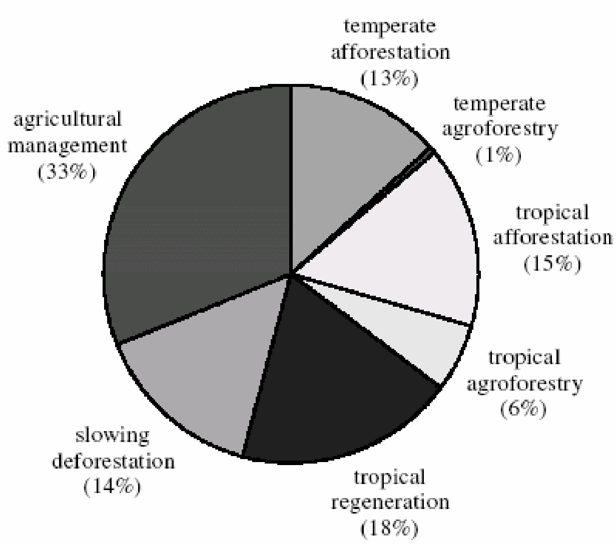
- **Modified forest management:** This approach includes, among many things, lengthening of forest rotation cycles, low impact harvesting methods to reduce carbon emissions, reduced impact logging, controlling stand density, and reducing regeneration delays (IPCC, 2001b);
- **Agroforestry:** The intentional growing of trees with crops, pasture, and/or animals. This alternative to standard agricultural practices requires less energy intensive operations, sequesters more carbon than traditional agriculture, and provides a wide range of environmental benefits (DOE, 1994, Workman and Allen, 2004). Other agricultural practices are discussed in Section 6.1.2; and
- **Short rotation woody biomass plantations:** The growing of tree crops on cropland for wood fiber and other biomass to energy uses. Biomass to energy practices are discussed in more detail in Section 6.2.2.

Carbon sequestration through one of these forest practices is more appropriate for forest landowners already engaged in the forest harvest and regeneration business. However, these practices are mentioned in the event an enterprising utility is able to find forest landowners willing to alter their forest management and operation practices and give the resultant carbon offsets to the utility.

In addition to carbon sequestration, forestry projects provide an additional suite of ancillary benefits. These range from the reduction of sediment runoff (erosion control) and improvement of water quality to increasing or preserving wildlife habitat and restoring degraded lands. However, GHG emissions are associated with the initial site preparation and treatment involved in forestry projects. Emissions can come from machinery, soil preparation and treatment, tree planting, vehicles used for transportation, and road building.

As previously mentioned, the potential for leakage and retransmission of GHGs are higher in projects involving land use changes such as forestry projects. Leakage concerns primarily include the displacement of the GHG emitting activity to another area. A forest project which simply displaces a housing development to a different tract of land is not really

Figure 6.2.1. The potential of various land-management activities to mitigate global emissions of CO2 by increasing the carbon-sink potential of forestry and agriculture or reducing deforestation. (Source: Malhi et al., 2002)



mitigating GHG emissions (CCAR, 2004). The potential for retransmission of GHGs is present throughout the duration of the forest project. Natural tree mortality and disturbances, such as fire or disease, will affect the permanence of the carbon that has been sequestered.

Summary of Key Considerations for Forest Sequestration Options:

- The CO_2 sequestration capability of a forest project varies with local ecological conditions such as soil and forest types, and local climate conditions.
- There are GHG emissions associated with implementing forest projects. These include emissions from machinery, vehicles, prescribed burning, chemical soil treatment, or road building during site preparation and tree planting.
- Permanence is not guaranteed. There is potential for retransmission of GHGs (forest becomes a source) at any time during the life of the project due to fires, disease, and natural tree mortality.
- A forest becomes a source of GHGs when the following activities occur:
  - Trees are harvested.
  - Trees and/or other forest vegetation are burned by natural or man-made fires.
  - Tree mortality occurs due to insects, disease, or weather.
  - Forest land is converted to other uses such as agricultural or urban uses (land use change).
- Potential for leakage is high. However, this can be circumvented with good project planning and awareness of a project's effects on the area surrounding a project.

6.2.2. Agricultural sequestration

Agricultural activities both emit and remove GHGs to and from the atmosphere. These activities mainly emit CO_2, CH_4, and N_2O. While CO_2 emissions can be sequestered, CH_4 and N_2O emissions can only be mitigated through reduction of emissions. There are two types of mitigation approaches that involve agriculture:

- The focus of this section is on enhancing the amount of carbon accumulation in soil and reducing the amount of CO_2, CH_4 and N_2O emissions through management practices such as no- and low-till plowing, thus lowering atmospheric GHG concentrations. This approach is distinct from forest sequestration in which carbon is stored in live biomass (IPCC, 2000); and
- Sections 6.3.2 and 6.3.3 focus on mitigation of CO_2 accomplished by utilizing crop biomass as a replacement for fossil fuels and/or energy-intensive fuel additives and as a long-lived product, such as timber for housing.

The natural process of CO_2 capture from agricultural practices accounts for substantial sequestration potential. In the US, net agricultural sequestration is estimated at 4 megatons (Mt) of C per year, compared to 207 Mt of C per year for forestry sequestration (Lewandrowski et al, 2004). The technical potential for agricultural sequestration, beyond what is currently occurring, is between 89 and 318 Mt of C per year (Lewandrowski et al, 2004).

The processes that increase agricultural sequestration of CO_2 include changes to cropland, grazing land and production practices (Table 6.2.2).

Table 6.2.2. Agriculture sequestration approaches (Lewandrowski et al, 2004).

Cropland	Grazing Land	Production Practices
Conversion to perennial grass	Rangeland management	Conservation tillage
Conservation buffers	Pasture management	Improved crop rotations and winter cover crops
Restoration of wetlands		Elimination of summer fallow
		Use of organic manure and byproducts
		Improved irrigation management

Conversion to perennial grass & Conservation buffers

Options to increase sequestration on cropland include conversion to perennial grass, and conservation buffers. Conversion from cropland to grassland often increases the amount of carbon in the soil (IPCC, 2001c). At a sequestration rate of 0.25 to 0.51 tons per acre per year, this equates to a total sequestration potential of 26 to 54 MMTCE per year (USDA, 2004). Conservation buffers are vegetative strips installed alongside streams on agricultural land to minimize erosion and non-point pollution (Lal et al., 1998). The USDA's Conservation Reserve Program (CRP) has set a target to increase the area of conservation buffers to 3.2 Mha by 2020. At a sequestration rate of 50 grams of C per square meter per year, this equates to a total potential of 1.6 MMTCE per year (Lal et al., 1998).

Restoration of wetlands

The restoration of wetlands can increase carbon sequestration and decrease methane emissions. Methane emissions occur as a result of microbial breakdown of organic compounds in anaerobic conditions. (Smith and Conen, 2004). Most emissions occur in wetlands, rice fields, and landfills. (Smith and Conen, 2004). The Wetlands Reserve Program, as part of the 1990 Farm Bill, establishes long-term easements that prevent wetlands drainage and resulting methane emissions (Lal et al., 1998). Total sequestration potential is estimated at 5 MMTCE per year (USDA, 2004).

Rangeland & Pasture management

Rangeland and pasture management are options for grazing land. Grassland, which includes grazing land, has inherently high soil organic matter content (Conant et al., 2001). Examples of management practices that can increase sequestration rates include fertilizer use, manuring, irrigation, and grazing management (Conant et al., 2001 and IPCC, 2001c). These practices increase sequestration by increasing the amount of crop residue that is returned to the soil (IPCC, 2001c). Estimated sequestration rates for these practices range from 0.10 to 1.30 tons per acre per year (USDA, 2004). Total sequestration potential is between 11 and 36 MMTCE per year (USDA, 2004).

Conservation tillage

Conservation tillage has been used for more than 50 years as a farming method to conserve soil and water. Conservation tillage, which includes no-till, and reduced tillage, is defined as any tillage or planting system that maintains at least 30% of the soil surface covered by residue after planting (Lal et al., 1998). Plowing and soil turnover, from conventional tillage, are major reasons for CO_2 emissions from soils (Lal et al., 1998). As conservation tillage can be applied to both cropland and grazing land, total sequestration potential is between 35 and 107 MMTCE per year (USDA, 2004).

Other production practices

Other production practices include changes to crop rotations and fallow. Crops grown in rotation often produce more and better quality plant matter than those grown in monoculture (Lal et al., 1998). In addition, crop management strategies that alter the timing, placement, quantity and quality of crop residue can affect soil carbon content (Lal et al., 1998). Changes to fallowing practices can also increase sequestration. Summer fallow is common in areas of low rainfall where cereal grain is grown. The practice of summer fallowing decreases soil carbon content by decreasing crop residue input and increasing decomposition and erosion (Lal et al., 1998). These two approaches account for between 6 and 18 MMTCE of sequestration potential per year (USDA, 2004).

Agriculture sequestration has beneficial ancillary impacts on the environment including, improvements in soil and water quality, provision of conservation buffers, and restoration of wetlands. Conservation programs utilizing conservation tillage have been found to reduce erosion as sequestration increases (Lal et al., 1998). The use of conservation buffers on agricultural lands and around streams has also been found to increase sequestration and reduce flooding and water pollution (Lal et al., 1998). Water quality can also be increased through the restoration of wetlands. Wetlands accumulate peat that affect CO_2 levels, and filter pollutants and store sediments loosened by erosion (Lal et al., 1998). The preservation of wetlands can also lead to the avoidance of GHG emissions. These are important benefits that a utility should seek out in a mitigation project that use agricultural sequestration.

As discussed earlier, permanence and leakage are important considerations in the design of an agricultural sequestration program. Leakage can occur in various ways. 25% of the carbon stored in wetlands can later be released as methane emissions (Lal et al., 1998). Several studies have shown that the adoption of no-till can increase N_2O because of compaction, reduced porosity, and increased denitrification (Smith and Conen, 2004). The production and use of nitrogen fertilizer to increase soil organic matter can negate any carbon sequestration gains (Schlesinger, 1999). In addition, CO_2 emissions in the use of irrigation to increase crop productivity can be greater than any sequestration gains (Schlesinger, 1999). A full accounting of project baseline emissions and net mitigation must be conducted to determine the true benefits of an agricultural sequestration project.

Summary of Key Considerations for Agricultural Sequestration Options:

- Land-use change to forestry has the greatest sequestration potential for agricultural land. However, existing practices of farmers and landowners can also provide agricultural sequestration benefits. Incentive payments for sequestration can partially offset losses in crop revenue.

- Agricultural sequestration approaches are susceptible to loss of mitigation benefits due to impermanent GHG sequestration and/or leakage. These losses can be reduced through a proper incentive program and a full accounting of emissions.

- Environmental ancillary benefits of agricultural sequestration include improvements in soil and water quality, and restoration of wetlands.

6.2.3. CO_2 capture and separation technologies

The two primary types of CO_2 capture and separation technologies currently available are pre-combustion and post-combustion capture. For utilities that use an integrated gasification combined cycle (IGCC) process, separation of CO_2 from a waste stream can be accomplished at the pre-combustion phase. Capture and separation at the post-combustion phase is the best option for conventional, natural gas- or coal-powered utilities. Of the two approaches, pre-combustion separation is the most cost effective (White, 2003).

Pre-combustion capture

For IGCC processes, a fuel gas mixture of primarily CO, CO_2, and H_2O is created by the reaction of a fossil fuel source with oxygen and burned to generate power in a gas turbine combined cycle. The gas mixture undergoes a second reaction with steam and a catalyst to convert CO to CO_2 (Anderson & Newell, 2003). A physical or chemical absorbent is then used to extract the relatively high concentration of CO_2 (40-60%) from the gas mixture prior to combustion (GEO-SEQ, 2004). Studies indicate that a physical absorbent such as Selexol (glycol-based) or Rectisol (cold methanol) is preferable over a chemical absorbent for pre-combustion capture processes (White, 2003; Anderson & Newell, 2004). Costs associated with pre-combustion capture options range from $140 ($142) to $150 ($150) per MTCE for new and retrofitted utilities, respectively (Anderson & Newell, 2003).

Post-combustion capture

Post-combustion CO_2 capture from conventionally powered utilities occurs by separating CO_2 from the exhaust stream using a chemical absorbent such as monoethanolamine (MEA) (White, 2003). CO_2 composes approximately 5% and 14% of the exhaust streams for natural gas and coal, respectively. These low CO_2 concentrations at the low pressures in post-combustion processes, coupled with the energy requirements of regenerating the chemical absorbent result in cost estimates of $230 ($234) and $190 ($293) per MTCE for new and retrofitted utilities, respectively (Anderson & Newell, 2003). To reduce or eliminate the need for separation technologies, conventional utilities could combust fuel with oxygen rather than air to increase the exhaust stream concentrations of CO_2 and lower concentrations of impurities such as NO_x (Anderson & Newell, 2003). However, current estimates are that the energy required for production of oxygen makes this more expensive than capture options.

Both types of capture options have environmental issues that must be considered. Environmental release of toxics (e.g., mercury) from fossil fuels need to be controlled and other impurities, such as SO_x and NO_x, are corrosive and require monitoring to prevent fouling of separation and capture equipment. If these issues require additional control mechanisms beyond that of regulations, the costs should be factored into the cost of capture and storage of CO_2.

The selection and cost of a separation and capture technology should take the following factors into consideration: the partial pressure (i.e., concentration) of the CO_2, the percent of recoverable CO_2 from the exhaust stream, presence and concentration of impurities (e.g., particulates, SO_2 and NO_x), and capital and operational costs (Herzog et al., 1993). Both capture technologies are mature and have been used extensively in various industrial processes for 20-30 years (IPCC, 2001). However, thermal inefficiencies result in a 40-percent loss for post-combustion and 15-percent loss for pre-combustion (Anderson & Newell, 2003), further eroding the overall avoidance of CO_2 atmospheric emissions.

Summary of key considerations for Capture and Storage Technologies:

- Capture, purification (when applicable), and storage of CO_2 represent a significant investment in initial and working capital and therefore needs full consideration with regards to any type of subsequent geological sequestration.

- A large percentage of government research and development funding for GHG mitigation is towards industrial capture and storage technologies. Though not conclusive, this level of funding indicates the likely acceptance of such technologies in future regulations.

- Pre-combustion CO_2 capture (e.g., IGCC technology) provides cost-saving benefits relative to post-combustion and offers additional benefits such as reduced criteria pollutant emissions as well as increased fuel use efficiency.

6.2.4. Geological sequestration

The process of capturing, separating, transporting, and injecting CO_2 exhaust into various geological formations is one of the primary means by which a utility can mitigate their CO_2 emissions (White, 2003). Herzog (1997) ranks and summarizes the various geological sequestration options that are of primary research and business interest (reproduced in Table 6.2.4.a.).

Table 6.2.4.a. Comparison of geological storage options (Source: Herzog, 1997).

Storage Options	Relative Capacity	Relative Cost	Storage Integrity	Technical Feasibility
Active Oil Wells (EOR)	Small	Very Low	Good	High
Coal Beds	Unknown	Low	Unknown	Unknown
Depleted Oil/ Gas Wells	Moderate	Low	Good	High
Deep Aquifers	Large	Unknown	Unknown	Unknown
Mined Caverns/ Salt Domes	Large	Very High	Good	High

Purification and injection of mined CO_2 for enhanced product recovery has been a common, well-understood practice for 30 years (Beecy, 2002). The technology associated with exhaust stream CO_2-injection is readily available. However, the cost effectiveness (relative to other mitigation options) of capturing, separating, and transporting the CO_2 as well as the permanence of sequestration are primary concerns associated with geological sequestration (Johnson-Keith, 2004).

Approaches involving oil wells, coal-beds, and natural gas fields are potentially more cost effective because they can enhance fuel extraction while sequestering CO_2 (Yamasaki 2003). However, this benefit might be offset somewhat by costs associated with long-distance transport of CO_2 from the exhaust stream to an injection site (transportation costs have been estimated at an average $8.00 ($8.12) per MTCE removed or reduced per 100 kilometers (Anderson & Newell, 2003). A utility could minimize these costs by selecting a geological injection project that is located close to the exhaust stream. Reducing transportation costs might be accomplished more readily with projects involving injection into geological formations such as salt domes and saline aquifers that are ubiquitous throughout the U.S. (White, 2003). Furthermore, in terms of permanence – keeping sequestered CO_2 out of the atmosphere – there are lower transmission-to-atmosphere rates associated with salt domes and saline aquifers (Oliver, 2004).

Oil and gas reservoir injection

Naturally-occurring CO_2 has historically been mined and injected into aging reservoirs to displace oil and natural gas, thus increasing the viability of the reservoirs beyond optimum production periods (GEO-SEQ, 2004). During calendar year 2000, approximately 9 MTCE was injected into depleted wells (Anderson & Newell, 2000). Oil well injection of waste CO_2 that is separated and captured from the exhaust stream could act as a surrogate for mined CO_2. The ancillary benefit of the enhanced oil recovered (EOR) could partially offset the cost of separation and capture (Anderson & Newell, 2003). U.S. domestic capacity for oil wells is estimated at 25-30 Gt of carbon equivalent with global capacity estimates of 130 Gt of carbon equivalent (Anderson & Newell, 2003). Approximately 85 m^3 of CO_2 is stored per barrel of oil produced (Gunter, 2001).

Of the geological storage approaches, injection into retired or aging wells poses the fewest safety risks because the waste CO_2 is contained within a geological structure that has retained pressurized fluids or gas for millions of years. However, potential retransmission of CO_2 to the atmosphere is possible as is contamination and acidification of groundwater, thus constraining such operations to specific reservoirs and requiring monitoring costs (Anderson & Newell, 2003). Such projected costs are offset somewhat by the potential savings of using a waste stream source of CO_2. Given the sizable amount of naturally occurring CO_2 that is currently mined for EOR projects (30 Mt/yr) there is significant room for expansion from the current 7 Mt/yr use of waste stream CO_2 (Beecy, 2002).

Coal bed injection

The solvent-like properties of CO_2, when injected into deep, difficult-to-mine coal-bed seams, result in the enhanced recovery of CH_4 (a process called enhanced coal bed methane recovery (ECBM)) (White, 2003). In combination with dewatering and depressurizing methods, ECBM using CO_2 is becoming a significant source of CH_4. In 2002, it accounted for 8% of U.S. CH_4 production (GEO-SEQ, 2004). Some studies of coal bed injection have estimated a 0.5:1 ratio of recovered CH_4 to sequestered CO_2 , but other studies have suggested this ratio can reach 1:1 with the injection of mixed composition flue gas rather than pure CO_2 (Gunter, 2001). U.S. Domestic capacity for this approach is estimated at 464.4 MMTCE with worldwide capacity 82-263 Gt of carbon equivalent (White, 2003; Gunter, 2001). Estimates of recoverable CH_4 in the U.S. are 2.5×10^{12} cubic meters (2.5 Tm^3) with worldwide estimates at 84-262 Tm^3 (White, 2003). The successful injection of raw exhaust streams (composed of 12% CO_2) into coal-bed seams producing CH_4 potentially eliminates the need for separation technologies and costs (White, 2003). Uncertainties about the physical, chemical, and thermodynamic processes that occur with CO_2 injection create environmental concerns (White, 2003). For example, coal swelling occurs as the coal expands with absorption of CO_2, thus reducing the overall capacity and permanence as a CO_2 reservoir as well as restricting the flow of recovered CH_4 (GEO-SEQ, 2004).

Saline aquifer injection

Saline aquifers are layers of porous rock that are saturated with brine (GEO-SEQ, 2004). The ubiquity (Figure 6.2.4.b.) and large potential volume of saline aquifers suggest that CO_2 injection into these formations is likely to be a long term source of mitigation. White et al. (2003) estimated that 65% of U.S. utilities are located near to a saline aquifer (shaded area of U.S. map in Figure 6.1.4.b). Gross estimates of U.S. capacity for storage range from 1.5 to 150 Gt of carbon equivalent with global capacity from 95 to 3,000 Gt of carbon equivalent (White, 2003). Minimized transport costs coupled with the maturation of injection technology are arguments for adopting saline aquifer injection options on a wider scale (White, 2003). Development of injection projects has demonstrated the capacities of saline aquifers to accommodate large quantities of waste CO_2 (e.g., the Sleipner project in the North Sea and the Weyburn Oil Field in Canada) (GEO-SEQ, 2004).

As with other injection approaches, environmental concerns exist. These include uncertainties about the biogeochemical reactions caused by injected CO_2, potential groundwater contamination and induced seismic activity. Reaction of the injected CO_2 with minerals could form bicarbonate solids. This could prove a hindrance to injection if the surrounding area were to be "plugged," but it might turn out to be a realized benefit if the bicarbonate can be recovered and used (White et al., 2003). Groundwater contamination is possible, but unlikely due to the geological separation between deep saline and shallower fresh water aquifers (Anderson & Newell, 2003). Finally, concerns over inducing seismic activity could limit injection to certain aquifers or reduce total amount of CO_2 -storing potential by maintaining conservative pressure ceilings.

Figure 6.2.4.b. Saline aquifers (shaded) in the U.S. based on U.S. geological survey. (Source: Bergman and Winter, 1996).

Salt dome injection

A salt dome is a geological formation that results from a process known as diapirism, the upward movement of low-density rock material (e.g., salt, magma and shale) through higher density rock material, often forming an anticline that facilitates the trapping of gases beneath it (Schlumberger, 2004). Much like saline aquifers, salt domes are viable CO_2 sequestration sites due to their large storage capacity as well as proven relative permanence based on historical use for storing petroleum, compressed air and natural gas (Herzog, 1997). Additionally, experiments with injection of waste CO_2 into a salt dome formation near Houston, Texas have verified the high permanence of these structures (Doughty and Hovorka, 2004). However, the costs associated with injection of CO_2 waste are high because the brine from the salt dome must be first be excavated. This creates an additional waste stream that lacks any significant use. The cost effectiveness of this approach is further diminished by the energy costs of such mining activities (Herzog, 1997).

Summary of key considerations for Geological Sequestration:

- Tradeoffs exist between revenue generating strategies (e.g., EOR or ECBM) that may incur transportation costs and non-revenue generating strategies (e.g., saline aquifers) that have low transportation costs due to the ubiquity of some types of geological formations such as, saline aquifers.

- Utilities need to be aware of the uncertain liabilities associated with geological injection. Including premature retransmission of stored GHG and other environmental and human safety concerns with regards to reservoir integrity.

- A vast amount of government funding goes to capture and storage technology development. This indicates that regulatory acceptance in the U.S. is likely.

- Aside from variable costs such as transportation, coal bed injection offers the least expensive source of geological sequestration due to the apparent ability to inject unpurified exhaust streams, thus eliminating capture and separation technology requirements.

6.2.5. Mineral carbonation

Mineral carbonation of exhaust stream CO_2 is being intensively researched as a viable form of long-term carbon storage. The industrialized process emulates and expedites the natural chemical transformations that occur in the mineralization phase of the carbon cycle. The resulting, solid bicarbonate products are stable and inert (Seifritz, 1990). Two forms of carbonation have been extensively studied.

Silicate weathering involves reacting CO_2 with naturally occurring minerals or waste product minerals to produce mineral carbonates. A ratio of approximately 2:1 is estimated of mineral sources required for converting CO_2 to carbonate. Sources of minerals for the process include magnesium and calcium silicates as well as asbestos and concrete wastes, iron, steel slags, red mud, and coal fly ash (Yamasaki et al., 2003). Mining estimates for virgin minerals range from \$30 (\$31) to \$35 (\$36) per MTCE. Higher costs are associated with recycling waste products for minerals due to preprocessing requirements. Natural resources are estimated at more than 10,000 gigatons (10^9) in mineral deposits available worldwide (Lackner 2003; Wolf et al., 2004). Issues with carbonation process by silicate weathering are the high energy inputs and costs required for mining new mineral sources or extracting minerals from waste products, and achieving the high temperature and pressure necessary for reaction (150°C and 15MPa CO_2) (Wolf et al., 2004). Cost estimates vary with location of the exhaust stream relative to mineral sources and the means and source of waste product disposal; estimates range from \$220 to \$360 per MTCE (Anderson & Newell, 2003).

The second form of carbonation is Accelerated Weathering of Limestone (AWL). In this process, carbonates such as limestone react with exhaust stream CO_2 and water to form dissolved calcium bicarbonate that is then released to the ocean where large quantities of these ions are naturally present (Rau, 2004). AWL is more technically feasible than silicate weathering due to the lower required energy inputs: AWL does not require separation of CO_2 from the exhaust stream; the necessary reactions can occur in ambient temperature and pressure; and a waste stream of limestone (20% of limestone production results in currently unusable fine particulates) can be utilized. The waste products (Ca^{2+} and $HCO3^-$ in solution) are relatively benign and possibly benefit marine biota by enhancing coral growth rates (Langer, et al., 2004).

Furthermore, limestone is already used for desulfurization processes and therefore represents a lower additional impact from indirect activities to those associated to silicate weathering. Concern with release of impurities resulting from the chemical reaction with the exhaust stream and impacts near injection site prior to dilution need further research. Cost estimates vary with location of the exhaust stream relative to sources of limestone and the disposal site with estimates ranging from $11 ($11) to $110 ($112) per MTCE.

Summary of Key Considerations for Mineral Carbonation:

- AWL carbonation is a more likely candidate for cost effective mitigation.
- Both carbonation technologies remain in a research and development phase and are not commercially available.
- Ancillary environmental and economic costs and benefits, such as the mining of limestone and the use of waste products, are central issues for mineralization.

6.2.6. Ocean sequestration

Global oceans are one of the largest terrestrial reservoirs of carbon, storing approximately 38,000 Gt of Carbon and taking up an additional 1.7 Gt C/yr. Natural carbon uptake occurs through either diffusion of CO_2 at the air sea interface or carbon uptake by photosynthetic plankton during primary production. Warm surface waters are saturated with CO_2 but the cold waters of the deep are under-saturated. The opportunity for increasing oceanic uptake of carbon lies in enhancing the amount of carbon that is exported to the deep ocean. There is an estimated deep ocean sequestration potential of 1400 to 20,000 Gt C (DOE, 2002, Yamasaki et al., 2004). There are currently two proposed methods of sequestering CO_2 in the deep ocean.

Ocean seeding

Ocean seeding involves the addition of a fertilizing nutrient – in most cases iron sulfate –directly to the ocean surface to stimulate phytoplankton growth. The elevated levels of photosynthesis lead to capture of CO_2 in surface waters. A portion of the carbon sinks into deeper waters as fish feces or dead phytoplankton. A percentage of the originally captured carbon (<.1%) is permanently sequestered to the ocean floor (Schlesinger 1997). Small and meso-scale (10 –100km^2) seeding experiments in the polar Southern Ocean have demonstrated that iron additions create a persistent phytoplankton bloom (Boyd 2000, Coale 2003). A recent study indicates that the ratio of iron (in tons) addition to CO_2 absorption (in tons) is 1: 10,000-100,000 (Coale 2004). This bodes well for economic scalability of ocean seeding, potentially bringing the abatement costs to $7- $30 ($7.50-$32) per MTCE (Adhiya and Chisholm, 2001).

Despite recent, favorable data from ocean seeding experiments, uncertainties in the processes and downstream outcomes of ocean fertilization raise significant questions about the true benefits of this approach. At this point, researchers cannot assert that ocean seeding is a useful abatement approach. Preliminary calculations of the amount of sinking (i.e. sequestered) particulate carbon as a function of iron additions indicate that massive areas of ocean would need to be fertilized to achieve worthwhile benefits (Buessler, 2003). Furthermore, the possibility of severe, negative ancillary impacts to the environment as a result of seeding are the subject of concern and generate scientific and public debate (Chisholm, Fallowski, Cullen, 2001; Lawrence, 2002).

Summary of Key Considerations for Ocean Seeding:

- The efficacy of ocean seeding as an approach to sequestering carbon is unknown.
- Associated with ocean seeding are potentially severe, negative ancillary environmental harms.
- Proposed ocean seeding projects have elicited strong objections from the public, raising concerns about public perceptions issues for a municipal utility.

Ocean injection

The capture of CO_2 from industrial waste streams and subsequent injection into the deep ocean has been proposed as another way of enhancing the carbon uptake of global oceans. There are two ways in which CO_2 could be transported into the ocean. One way would be to simply use a system of pipelines extending from the CO_2-capture source out into the ocean. The other way would be to transport CO_2 via tanker to an injection platform, a system similar to that used for transporting liquified petroleum gas. Pipelines for either method would carry CO_2 in either a liquid or dense gas phase and would need to extend well below 1500m for CO_2 to remain dissolved in seawater and to minimize environmental impacts to the upper ocean (IEA, 2002).

Although this method sounds highly attractive as a way to sequester gigatons of carbon, there are many environmental concerns have not yet been resolved. First and foremost is the concern over the effect on marine organisms at the injection point. Mixing and dissolution of water in the deep ocean is a slow process, current velocities are on the order of a couple centimeters per second, and there are concerns that injection of large amounts of CO_2 will lead to localized increases in pH (IEA 2002, Sato & Sato, 2003, Yamasaki, 2004). Organisms in the deep ocean are highly adapted to the stable conditions found in the deep ocean and may prove unable to adapt to rapid environmental changes (Barry et al., 2004).

Technologically, mid- and deep-ocean injections of CO_2 are considered feasible. The necessary equipment for a shore, ship-based or ocean-platform injection approach would be modeled on existing technology (e.g. drilling, compression, transportation and other steps) from the petroleum industry. However, use of the technology in this new application requires significant design changes and testing that have not yet occurred.

Summary of Key Considerations for Ocean Injection:

- Potentially severe, negative environmental impacts are associated with ocean injection. Research is ongoing to assess the types and degrees of impacts to deep ocean ecosystems; and
- Although the physical infrastructure for ocean injection is based on existing technologies, necessary design changes to facilitate commercial implementation have yet to be completed.

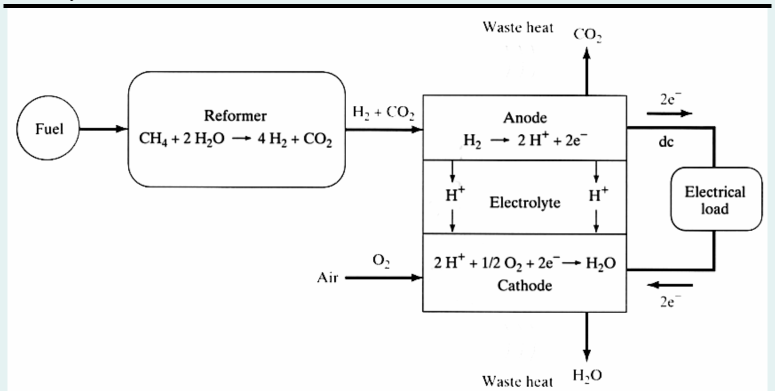
6.3. Capture/Use Options

GHGs can also be captured or absorbed and then processed and/or used in some form. This category includes methane capture from landfills, dairy farms and wastewater treatment facilities (for flaring or electricity generation), and absorption of CO_2 in biomass that is then used in products or to supplant fossil fuel energy sources. Section 6.3.1 describes the technique of methane capture and use, Section 6.3.2 and 6.3.3 describe the transformation of biomass to energy or products to mititgate GHG emissions.

6.3.1. Methane capture and use

After carbon dioxide, methane is the leading anthropogenic contributor to global warming, accounting for nearly 10% of the total U.S. GHG emissions. By mass, methane has approximately 21 times the global warming potential of carbon dioxide, however unlike CO_2, methane can be combusted to produce energy. Therefore, for some methane sources, opportunities exist to cost-effectively reduce emissions by capturing methane and using it as fuel (EPA, 1999). Methods of GHG abatement through methane combustion include capture and flare, direct gas use, or electricity generation. Electricity generation is the most attractive option because not only are revenues generated by the sale of electricity, but a secondary reduction in GHG can be realized because this electricity is generated through a renewable source of fuel. Selling renewable electricity to the grid results in an offset in electricity generation that would otherwise have been created through the combustion of fossil fuels[6]. Methane capture and subsequent electricity generation is currently implemented almost entirely by the use of reciprocating internal combustion (IC) engines because they are relatively inexpensive, efficient and a well-understood technology (EPA, 1999).

Figure 6.3.1.a. Basic components and schematic of a fuel cell system. (Source: Masters, 1998)



While IC engines have been the industry standard in methane capture and use projects for many years, the desire for cleaner, more efficient electricity generation has promulgated the development of promising new technologies such as direct methane fuel cells (DFCs). Fuel cells, as shown in Figure 6.2.1.a, utilize an electrochemical reaction between hydrogen and oxygen to produce electricity and water, while virtually eliminating harmful combustion-related emissions except for CO_2. For a DFC, methane provides the source of hydrogen, and it needs to be relatively pure. Biogas, the principle source of methane, is the product of anaerobic waste treatment processes (discussed in more detail later) and is composed 60 and 80% methane with the rest CO_2 and other trace contaminants such as H_2S. Biogas can be directly utilized with an energy content of 600-800 BTU/ft^3 (EPA AgSTAR Guide), however if concentrations of impurities (such as H_2S) are high, scrubbing prior to utilization may be required to reduce corrosion. Although the capital cost requirements for fuel cells are greater than that of IC engines, they are still desirable in certain circumstances, especially when utilizing on-site cogeneration (simultaneous electricity and heating) which can improve the fuel cell's efficiency to upwards of 80% (Masters, 1998).

For electricity generated through the combustion of natural gas, the EPA estimates an emission factor of 14.47 kg of carbon emitted per MMBTU (EPA, 2004c), therefore significant reductions in carbon emissions can be

[6] For more information about renewable energy see Section 6.1.2: *Renewable Energy Transitions*

realized by offsetting natural gas combustion with biogas-derived electricity generation. Many cost effective opportunities exist for the capture and use of methane emissions, specifically from the anaerobic decomposition of organic wastes contained in landfills, livestock manure, and wastewater treatment plants as a method of mitigating GHGs.

Throughout the discussions of methane-capture approaches, it is important recognize that in calculating the net GHG reduction benefit of a methane capture project, one must be careful to account for the CO_2 emissions that are a result of the combustion process. The combustion of 1 molecule of methane will produce 1 molecule of CO_2. However, since methane has a global warming potential 21 times higher than CO_2, these projects provide overall GHG reduction.

Landfill methane capture

In 1997, emissions from landfills represented 37% of the total U.S. methane emissions and 3.7% of the total U.S. GHG emissions, approximately 66.7 MMTCE. Municipal solid waste landfills are responsible for 93% of the U.S. landfill methane emissions, while industrial landfills account for the remaining 7%. The EPA expects landfill methane emissions to decrease in the future due to the "Landfill Rule" (New Source Performance Standards and Emissions Guidelines).[7] Although this regulation is aimed at reducing the emissions of non-methane organic compounds (NMOCs), it also controls methane emissions (EPA, 1999). Still, over 600 undeveloped U.S. landfill sites are potential capture/use projects and thus, many opportunities exist for the implementation of a voluntary project aimed at reducing methane for the primary purpose of GHG mitigation[8].

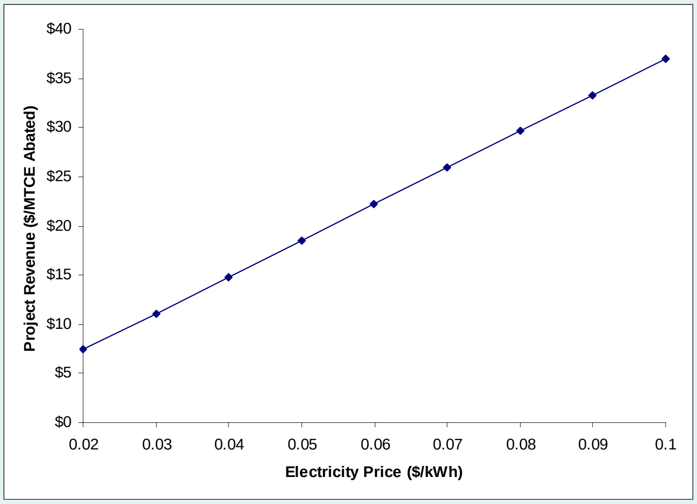


Figure 6.3.1.c. Expected landfill methane project revenue per MTCE abated at varying electricity prices. (Information for calculations obtained from EPA, 1999. Revenue calculations are shown in Appendix B.)

All landfill methane projects include a gas collection system. Once this is in place, three options for the captured methane exist: flaring, direct use by a nearby customer, or use in electricity generation. Many U.S. landfills have implemented flare systems without utilizing energy recovery, but typically these landfills are either required to flare for air pollution control or as a means of odor reduction. Direct gas use is a feasible option when a nearby customer (ideally within five miles) has a use for medium-BTU fuel for processes such as drying operations, kiln operations, and cement and asphalt production (EPA, 1999). The most common, most cost effective, and best method for GHG mitigation is electricity generation.

The EPA has compiled a table that details the expected power generation from landfills of different sizes as well as associated costs from implementing the methane recovery and electric generating system (assuming the use of an IC engine). Their analysis estimates that for a large landfill of 2,918,000 metric

[7] The Landfill Rule requires landfill gas to be collected and flared or used for onsite electricity generation at landfills that (1) have a design capacity greater than 2.5 million metric tons (MMT) and 2.5 million cubic meters; and (2) emit at least 50 metric tons (MT) per year of non-methane organic compounds (NMOCs).

[8] A map of U.S. landfill gas energy project developments as well as candidate landfills by state is available at http://www.epa.gov/lmop/proj/index.htm.

tons (MT) of Waste in Place (WIP), 5 MW of power can be generated, corresponding to 43.8 x 10^6 kWh annually.

The total GHG mitigation capacity of a project of this size is approximately 40,000 MTCE per year. An estimated project lifetime of 20 years must be made in order to evaluate the cost per metric ton of carbon mitigated. Implementing a project of this size will cost approximately $9,456,000, corresponding to a carbon abatement cost of $10.25/MTCE. By selling the electricity generated by the combustion of landfill methane, significant revenue can be realized; at $0.04/kWh, revenue of approximately $15/MTCE can be expected from a landfill of any size. At higher electricity prices, revenues will increase substantially as seen in Figure 6.3.1.c. The GHG abatement capacity, project costs and associated revenue generation calculations can be found in Appendix B.

While the EPA only provides data on power generation and associated costs for landfills containing up to 2,198,000 MT WIP, a list of candidate landfills throughout the U.S. shows that the average size of these candidate landfills is 3,057,939 MT of WIP (EPA, 2004b). A spreadsheet of candidate landfills throughout the U.S. is included in Appendix B.

Livestock manure management

In 1997, emissions from livestock manure represented 10% of the total U.S. methane emissions and 1% of the total U.S. GHG emissions, approximately 17 MMTCE. Most of these emissions come from large swine and dairy farms that manage manure as a liquid. EPA expects methane emissions from livestock operations in the U.S. to grow by over 25% between 2000 and 2020, primarily due to increasing use of liquid and slurry manure management systems as farms trend towards larger, more concentrated numbers of animals (EPA, 1999).

Stored manure liquids and slurries decompose anaerobically and produce large amounts of methane-rich gas, called biogas. Biogas contains between 60 and 80% methane, with an energy content of 600-800 BTU/ft^3 (EPA AgSTAR Guide). There are available, cost-effective technologies (i.e. anaerobic digesters) that capture the methane produced by livestock manure management and make it available to use as an energy source. The recovered methane can be used for electricity generation, or in boilers to produce heat and hot water. Managing livestock manure in this manner also reduces foul odor and the risk of ground and surface water pollution, as well as converting organic nitrogen into high quality fertilizer (EPA, 2002a).

There are three biogas recovery technologies available that attempt to maximize the methane generation from manure, collect the methane, and subsequently use it to produce electricity and heat:

1. Covered anaerobic lagoons, the simplest type of recovery system, consist of a primary lagoon that is covered for methane generation and capture and a secondary lagoon for wastewater storage. This technology is often preferred in warmer climates, and when manure must be flushed with water as part of the normal farm operations.

2. Complete-mix digesters are tanks into which manure and water are added regularly. As new water and manure are flushed into the tank, an equal amount of digested material is removed and transferred into a lagoon. To speed the decomposition process, waste heat from electricity generating equipment is used to heat the digesters. Typically, complete-mix digesters are used at swine farms and in colder climates where covered lagoons cannot continuously produce methane year-round. They also are not recommended for dairy farms because of the high solids content of dairy manure. An important consideration regarding complete-mix digesters for GHG abatement is that they require a constant, elevated temperature to maximize methane production. In the absence of this management practice, it is difficult to quantify what the methane generation would have been had the rate of generation not been deliberately increased.

3. Plug-flow digesters are long concrete-lined tanks in which manure flows through in batches, or "plugs". As new manure is added at one end, an equal amount of manure is pushed out the other end. Like the complete-mix technology, waste heat from electricity generation is used to speed the decomposition rate. Plug-flow digesters are almost exclusively used in colder climates and at newly constructed dairies instead of lagoons (EPA 1999). It is important to note that a successful GHG mitigation project must be implemented at an already existing farm that does not currently capture its biogas emissions in order to achieve additionality.

A typical large farm contains 500 dairy cows or 1000 swine (EPA 1999), however the potential for methane generation and capture is much greater for dairy farms. Utilizing a covered anaerobic lagoon, a 500 cow dairy can expect a rate of methane generation of approximately 13,400 ft^3 per day, whereas a 1000 head swine farm can only expect 5,350 ft^3 CH_4 per day. The following GHG abatement capacity and cost analysis (discussed below) focuses solely on dairy farms utilizing covered anaerobic lagoons.

A 500 cow dairy with associated methane generation of 13,400 ft^3 CH_4 per day is equivalent to 538 MTCE per year, however approximately 17% of the captured carbon is re-released to the atmosphere during the combustion process. The direct methane capture coupled with the offset of fossil-fuel derived electricity results in a GHG reduction of approximately 518 MTCE per year. Over 20 years (the estimated project lifetime), the cost of GHG abatement is approximately $15.35/MTCE, while project revenue of $18.56/MTCE can be realized through on site electricity generation at $0.04/kWh. The calculations can be found in Appendix B.

Wastewater treatment and biogas capture

Compared with landfills and livestock manure, wastewater treatment is considered to be a relatively small source of GHG emissions in the U.S. (EPA 1999). However, treatment of human waste by conventional wastewater treatment produces an average of 1 cubic foot of biogas per person per day. Biogas is a by-product of the anaerobic wastewater treatment process and because most wastewater treatment plants are primarily concerned with meeting water quality and biosolid disposal standards, they may not take advantage of the potential for energy production. Therefore, this biogas is generally captured and flared for air pollution control, especially at small and mid-sized treatment plants (Kitto, 2001).

Since on-site electricity generation at wastewater treatment plants is relatively new, there is a lack of literature describing the practice in great detail. However, an excellent example of how this type of project can be implemented is the El Estero Wastewater Treatment Plant in Santa Barbara, CA, which processes wastewater for a population of approximately 100,000 people. The treatment plant created a partnership with Alliance Power Inc. and Fuel Cell Energy (FCE) in 2004 to install direct methane fuel cells (DFCs) totaling 0.5 MW of power generation from biogas that is created during the anaerobic digestion process. As discussed earlier, DFCs are capable of generating electricity from methane without harmful combustion products by electrochemically converting the energy contained in the methane into electricity through flameless oxidation. The fuel cells were installed by Alliance Power and FCE through $2.25 million in funding provided by Southern California Edison. The electricity is sold back to the treatment plant at $0.02/kWh less than what they were previously paying. Not only will the use of fuel cells reduce annual NO_x emissions by 35,000 lbs, it is also estimated that annual CO_2 emissions will be reduced by 500 tons by displacing electricity that would have otherwise been produced through the combustion of fossil fuels (FCE, 2005). Calculations located in Appendix B show that the actual expected GHG reductions are nearly 634 MTCE per year. Assuming the Southern California Edison $2.25 Million grant represents the total cost of the system, at a project lifetime of 20 years, the cost of implementing this project is approximately $177/MTCE abated. Project revenue is assumed to be the $0.02/kWh reduction in cost for the wastewater treatment plant, which over a 20 year timeframe and an 8% discount rate becomes revenue of approximately $9/MTCE abated. It is important to note that the wastewater treatment plant did not have to bear the cost, while they are allowed to realize the revenue in electricity savings of approximately $88,000 per year. Calculations for the previous analysis can be found in Appendix B.

Fuel Cell Energy has identified over 550 municipal wastewater treatment facilities in the U.S. that are capable of producing enough methane from anaerobic gas digestion to fuel a 250-kilowatt or larger DFC power plant. Furthermore, wastewater treatment plants in California are required to provide onsite backup generation to address the critical functions of these facilities. Fuel cells could meet both continuous and backup generation requirements of these facilities (FCE, 2005).

Summary of Key Considerations for Methane Capture and Use Options:

- Methane has a global warming potential (GWP) between 21 and 23 times that of CO_2. Therefore, one metric ton of abated CH_4 is equivalent to 21-23 metric tons of abated CO_2. Calculations within this document use a GWP of 21.
- Methane and CO_2 co-occur in biogas. Thus treatment of methane as a separate gas requires prior separation of CO_2.
- When methane is burned, CO_2 is released during the combustion process. For every MTCE captured as methane, approximately 17% is re-released as CO_2 when combusted to produce electricity.
- The cost per MTCE abated of a given project is dependent on the lifetime of the project itself. Here, an assumption of 20 years per project has been made.
- Revenues are generally based on on-site electricity generation with subsequent sale to the grid. Utilities investing in a methane capture and electricity generation project may not directly receive monetary revenue.

6.3.2. Biomass to energy

The biomass-to-energy, or biofuels, abatement approach can be combined with forest and agriculture GHG sequestration approaches as well as renewable energy transition options. Under this approach, mitigation is accomplished through the *replacement* of fossil-fuel-generated energy. CO_2 is absorbed in the plants during the growing period, and then released during combustion, which result in no gain or loss of CO_2 overall. Biomass – crops and crop wastes from forestry and agriculture activities– is either combusted directly for electricity generation and heating supply or processed into a liquid biofuel that is then combusted (e.g. for transportation or heating). In absence of this switch, use of biofuel provides no GHG mitigation benefit; the CO_2 absorbed from the atmosphere during growth of the crop is released back to the atmosphere during combustion. With this issue in mind, utilities should consider biomass options as fuel *switching* approaches.

Inherently, biomass-to-energy approaches are attractive because of the marketable products (i.e. electricity or fuels) that are generated from the projects. However, if a utility is considering this type of approach, it needs to avoid potential pitfalls in the project implementation. The effectiveness of biofuels as a mitigation option depends heavily upon the circumstances of an individual project.

Projects for which crops are dedicated for biofuel production (i.e. "bioenergy" crops) provide less, or potentially no, GHG mitigation benefit. This is in contrast to projects that use biomass wastes as the fuel source. This difference in efficacies becomes clear in the process of quantifying the net GHG mitigation from projects under these two categories. For a dedicated crop approach, project GHG emissions (to the atmosphere) include those associated with crop preparation (e.g. emissions from the processes of soil preparation, seeding, fertilizer production/ transport/ application, weed control and harvest), transport of the crop, processing into a fuel, and combustion (Jungmeier, January 2000). Crop preparation emissions can be quite high for certain crop types and agricultural practices and thus substantially diminish (or eliminate) the marginal mitigation benefit of projects that have these steps. Of the total energy used in producing biofuels, agricultural production processes can account for 27-44% (Kim and Dale, 2004). For example, a corn-based ethanol production system is prone to this problem because of the relatively high nitrogen fertilizer requirements for corn growth. (Production of nitrogen fertilizers generates high levels of GHG emissions.)

For a project that utilizes residues (wastes) from a crop that was grown for other purposes (i.e. was not grown as a result of the mitigation project), these emissions associated with the crop itself are not subtracted from the mitigation benefits. Other processes that emit GHG still need to be part of the calculation (e.g. emissions associated with transport of the biomass wastes, processing into biofuels, and combustion). As a result, biomass projects that exploit waste streams should be prioritized over dedicated crop approaches.

Two main categories of biofuel switching opportunities for GHG mitigation are identified here: (1) use of biomass as an energy source in electrical power plants, and (2) production of biofuel liquids to replace fossil-fuel-based heating oils and gasoline or diesel (McCarl & Schneider, 2000; IPCC, 2001c). Sale of electricity or the liquid biofuels provides revenue streams for these approaches.

Biomass electricity generation

A major application is the use of biomass for electricity generation. Biomass direct fire generators (i.e. those that burn 100% biomass) are similar to traditional fossil fuel-fired plants; biomass fuel is burned in a boiler to generate steam which turns a turbine connected to electric generator (DOE Biomass Program, 16 November 2004f). These systems are usually smaller than coal-fire generators (20-50MW versus 100-1500MW) and tend to have lower efficiencies (~20%) because the smaller size reduces the opportunities for economies of scale and the cost effectiveness of installing efficiency-enhancing equipment (DOE Biomass Program, 16 November 2004e). McCarl and Schneider (2000) estimated a cost per MTCE of \$25-\$55 (\$29-\$64) for a transition from coal to biomass direct fire in the U.S. Biomass can also be substituted for a certain portion (usually ~5%) of coal fuel source in a traditional coal-fire plant. This co-firing approach requires some retrofit of existing coal-firing equipment (Ney and Schnoor, 2002). After calibration and tuning of the performance, the new system does not usually represent an efficiency loss (i.e. expected efficiency ranges from 33 to 37%) (DOE Biomass Program, 16 November 2004f). Fuel feedstocks for these projects are switchgrass (Ney and Schnoor, 2002; Jannasch et al., n.d.) and woody biomass such as hybrid poplar trees (Stanton et al, 2002).

Woody biomass feedstocks (e.g. hybrid poplar) can also be used for integrated gasification combined-cycle (IGCC) power generation (Craig and Mann, 1996). In this process, heating of the biomass breaks it down, forming a flammable gas which is then cleaned and used in combined cycle generation. Using IGCC, high generation efficiencies that are comparable to traditional CHP systems can be achieved (e.g. 60%) (DOE Biomass Program, 16 November 2004f). Cost estimates for an integrated gasification combined cycle approach using wood wastes ranged from -\$92 to -\$117 (-\$95 to -\$120) per MTCE (Sims, 2003). (The negative sign indicates a cost reduction due to implementing this approach because of the reduced fuel cost associated with biomass waste feedstocks.) Most gasification projects are small-scale, and are occurring abroad.

Modular electricity generation systems can employ similar techniques to those above, but they are implemented on a smaller scale for villages, farms and small industry. (DOE Biomass Program, 16 November 2004f). Implementation of these systems may be most practical for developing countries.

Biomass processing into liquid biofuels

Ethanol derived from agricultural biomass, can be substituted (wholly or partially) for gasoline thereby offsetting GHG emissions. Three categories of biomass can be used as feedstock materials for production of bioethanol. Sugar-rich crops (e.g. sugar cane, sugar beet and sugar millet) are fermented to produced ethanol. Starchy crops (e.g. corn, wheat, barley, cassara) are enzymatically or chemically transformed into glucose. This sugar is then fermented to produce ethanol. Cellulosic plant materials (e.g. wood, straw and corn and rice husks, corn stovers, and municipal green wastes) go through a hydrolysis step prior to fermentation to process cellulosic material for ethanol production (Scharmer, 1999; Gallagher, 2003). According to the U.S. Department of Energy's Biomass Program (3 November, 2004), this last process is still in development and is not yet commercially available.

Studies of the economic viability of ethanol substitution for petroleum indicate that substantial subsidies are required to make this approach competitive. The cost per gallon for ethanol production is on the order of $1.20-$1.35 (compared with $0.60 for gasoline) which corresponds to a mitigation cost of $250-$330 ($290-$384) per MTCE (McCarl and Schneider, 2000). (These cost estimates do not include the GHG mitigation-specific costs: project baseline calculations, quantification, monitoring and verification.)

The other category of liquid biofuels is biodiesel. Crops such as grapeseed in Europe, sunflower in France and Spain, soybean in the U.S. and Italy and palms in tropical climates, as well as waste cooking oils serve as feedstocks for biodiesel (Scharmer, 1999). After extracting the oils through physical processing of plant material (e.g. pressing), the oil is chemically treated in a transesterification process to produce alkyl esters, or biodiesel. (Scharmer, 1999).

Biomass projects combine features of agricultural and renewable energy approaches. As a result, biomass project baseline calculations are more involved than for other approaches. The type of fossil fuel that is being replaced (e.g. coal, natural gas, diesel) and the efficiency of the existing system play fundamental roles in setting the upper boundary of potential GHG offsets from biofuel switching (Jannasch, et al., n.d.). These two factors will be essential components of the project baseline calculation. In addition, the project baseline must incorporate tabulation of the emissions from the land under the business as usual scenario.

The crop type and siting (with respect to the use location), and agricultural practices also significantly affect the GHG mitigation benefit of a project. In general, annual crops are more energy intensive to grow, and support lower soil organic carbon levels than perennial crops (Table 6.3.2) (Cook and Beyea, 2000). As a result of these characteristics, annual crops are less desirable from a mitigation standpoint. Projects utilizing perennial crops or waste residues from annual crops have greater capacities to provide offsets to a utility. A case study of a proposed project for which a coal-fire plant would be transitioned to 5% co-firing of switchgrass (perennial) indicated net mitigation benefits of 305,500 MT of CO_2 equivalents per year (Ney and Schnoor, 2002). Furthermore, projects that involve conversion from annual cropping to longer cycles of harvesting (e.g. hybrid poplar) can result in higher soil organic carbon (i.e. greater mitigation) due to the land use change (Kim and Dale, 2004; Cook and Beyea, 2000).

As Table 6.3.2 indicates, corn production has relatively high CO_2 emissions. Numerous studies of the net energy benefits/losses of ethanol production from corn have reached conflicting conclusions. Shapouri et al. (1995, 2002) and Wang et al. (1999) showed net energy benefits, whereas Pimentel (1991, 2002) and Ulgiati (2001) found that energy required for producing ethanol was either equivalent to, or greater than, that its energy content. For corn, in particular, use of crop wastes (e.g. corn stovers and husks), as opposed to the crop itself, is advisable.

The discrepancies among the studies of corn-based ethanol production resulted from different assumptions about agricultural practices (Kim and Dale, 2004). This demonstrates how sensitive the mitigation benefits are to the specific details of project implementation. An advantage associated with biomass projects is the opportunity to combine agricultural sequestration practices (Section 6.2.2) with biofuel switching to optimize GHG mitigation potential, and potentially increase the viability of agricultural projects such as conservation tillage that were otherwise cost-ineffective.

Table 6.3.2. Comparison of energy requirements for different crop types. Calculations are based on conventional agricultural practices and transportation (i.e. fossil fuel-based).
(Information taken from Kim and Dale, 2004; Cook, 2000).

Crop Type (a=annual; p-perennial)	**Cumulative Energy Requirement** (MJ) to produce 1kg of crop	**Amount of GHGs emitted** (g of CO_2) per kg Produced	**Net Amount of Avoided GHG Emissions** (g of CO_2) per kg of Crop
Corn (a)	2.66; 2.3-2.8	286; 110-146	300 +/-80
Soybean (a)	2.04	163	
Alfalfa (a)	1.24	89	
Switchgrass (p) (herbaceous crop)	1.24; 0.72	147; 44	400 +/-140
Hybrid Poplar (p) (short-rotation woody crop)	0.48	30	550 +/-210 (3 yr rotation) 600 +/-220 (10 yr rotation)
Wood from existing forest			140 +/-30 (100 yr rotation) 30 +/-10 (400 yr rotation)

Project magnitude is a central issue with respect to this category of mitigation projects. Due to minimum project size requirements for cost-effective biofuel production, a single municipal utility would not independently pursue an entire project. As a result GHG mitigation via biofuels involves participation in a consortium to initiate new projects or investment in an existing project (e.g. directly in a CDM project, or indirectly through purchase of credits from a broker).

This last point about project magnitude raises issues relating to leakage and ancillary impacts.

1. Large land-use changes that shift crops from food to bioenergy production could have a profound effect on demand for agricultural land, leading to an unintended increase in conversions of fallow areas, native grasslands, and forested areas to annual crop growth, and resulting growth in GHG emissions. Prior to investing in a biomass project, a utility should check that leakage has been estimated and that it does not significantly reduce the mitigation benefits.

2. Ancillary impacts are also key considerations for biomass projects. Co-firing of biomass has been implemented in several U.S. coal power plants not only to reduce GHG emissions, but also SO_x and NO_x (Spath and Mann, 2004). Benefits are also expected for the agricultural industry by opening up new markets for farm commodities and revenue streams from the use of crop wastes (McCarl and Schneider, 2000). Depending on the circumstances of the project, environmental resource benefits could occur due to the transition from annual cropping. These might include greater water conservation, lower soil erosion and better habitat for native species (Cook and Beyea, 2000). Cook points out, however, that the reverse can be true as well; biomass projects can negatively affect biodiversity and other ecosystem components if they are implemented poorly.

Summary of Key Considerations for Biomass to Energy Options:

- Use of dedicated crops (as opposed to crop wastes) diminishes or, potentially, eliminates the mitigation benefits of the project due to the emissions from crop preparation that must be incorporated into the calculations of net GHG reductions.
- Biomass projects incorporate both agricultural and renewable energy transition components. As a result, project baseline emissions calculations will be more involved than for other options.
- The quantity of GHG mitigation from a project is highly dependent upon the energy source that is being displaced (e.g. coal, oil, etc), the type of crop, the previous use of the land and agricultural practices for the project.
- To optimize the benefits associated with an investment in a biomass option, projects can be designed to incorporate other GHG mitigation components such as conservation tillage or capture of CO_2 from biomass electricity generation.

6.3.3. Biomass to product

Two basic formats exist for biomass to product (BTP) projects. In the first category, sequestration is achieved through CO_2 capture in plant matter (e.g. trees) which is then harvested and processed into a long-lived product. Plantation-grown tree crops (usually hybrid poplar) are used in production of long-lived building materials such as plywood, decorative moldings, window casings, frame stock, blinds and furniture components. (Stanton et al, 2002). Other applications include bamboo products and use of crops and crop wastes in building materials.

An obvious benefit of the BTP approach is the revenue stream from the sale of the product. However, analyses of the wood products markets have found that "acceptance of hybrid poplar in conventional solid wood markets has not been wholly proven." (Stanton et al, 2002). It is also important to recognize that GHG benefits are only achievable if the land used for growing the trees for this purpose was previously used to produce crops (trees or otherwise) that could not be, or were not applied to, the long-term storage of carbon or the replacement of fossil fuel usage (e.g. crops for food, or tree plantations used in paper production). Furthermore, relative to other sequestration approaches in which the project owner maintains direct control over the carbon sink (e.g. trees, aquifer, etc.), the sale of the sink (e.g. lumber) to another entity eliminates the capacity to accurately quantify, monitor and verify GHG mitigation achieved by the project. This jeopardizes the permanence of the sequestration and introduces significant risks for the project owners. From a regulatory standpoint, this is a significant concern for project investors – they lack the ability to demonstrate their GHG offsets.

For the second BTP format, biomass replaces fossil fuel-based feedstock material in the production of short-lived commodity chemicals (e.g. biopolymer plastics). Although this approach has proven benefits for reducing non-biodegradable wastes, GHG benefits have not been demonstrated with these projects (Kurdikar, et al., 2001). More efficient production technologies are expected to improve efficacy, but they are still in development (Lynd and Wang, 2004).

Both types of BTP options raise the same leakage and ancillary impacts concerns that are associated with biomass to energy approaches. Specifically, use of hybrid poplar products can replace the use of native tree species and limit demand for logging in virgin forest areas. However, tree plantations support less biodiversity than native forest or grassland habitats. Thus the type of land use that is being replaced by the project defines key ancillary impacts.

Summary of Key Considerations for Biomass to Product Options:

- Due to the nature of BTP projects that involve sale of the carbon sink (e.g. lumber), accurate quantification, monitoring and verification of the net GHG mitigation achieved is not possible.
- Storage of GHGs achieved through BTP projects that involve production of a long-lived product is not fully permanent.

FOR FURTHER INFORMATION ON:

Forest Sequestration

- Bloomfield, J. and H.L. Pearson. (2000) Land use, land-use change, forestry, and agricultural activities in the clean development mechanism: estimates of greenhouse gas offset potential. *Mitigation and Adaptation Strategies for Global Change*, **5:** 9-24.
- Brown, S. (2002) Measuring carbon in forests: current status and future challenges. *Environmental Pollution* **116**: 363-372.
- California Climate Action Registry. (2004) *Forest Project Protocol*. California Climate Action Registry. Los Angeles, California.

Biomass to Energy

Overview of biomass to energy approaches and technologies

- [DOE] U.S. Department of Energy (2005). DOE, Energy Efficiency and Renewable Energy Program website: http://www.eere.energy.gov/biomass/

Efficiency improvements

Review of potential demand side reductions in the residential sector in California

- [CEC] California Energy Commission (April 2003). *California Statewide Residential Sector Energy Efficiency Potential Study*. Prepared by KEMA-XENERGY Inc. Sacramento, CA: CEC. Study ID #SW063, Vol 1 of 2. <www.cpuc.ca.gov/PUBLISHED/REPORT/30114.PDF>

7. GHG Mitigation Planning Process

The major objective of this guide is to help BWP and other small municipal utilities make sound decisions with respect to mitigation of Green House Gases (GHGs). The preceding chapters have provided the context for this decision process –the problem of climate change, the status of GHG policy, potential implications for utilities, evaluative criteria and the mitigation options themselves. This chapter synthesizes these various components into specific guidance for utilities.

A process for GHG mitigation planning is illustrated in Table 7 (located at the end of the chapter). The six steps follow the order and progression of the material presented in this guide. Some or all of these steps can be performed in-house or by a consultant depending on the utility's desires, funding, and corporate philosophy. Steps 1-4 are straightforward for a utility to perform on its own. For the remaining planning and subsequent implementation steps, utilities will likely require assistance from outside expertise. Specialized consultants can help gather preliminary data (including cost estimates) for mitigation options to ensure that utilities are well-informed and can effectively evaluate and select (Step 6) the best strategy for approaching GHG mitigation.

STEP 1: Establish desire and motivation to mitigate GHGs

This first step is a precursor to any mitigation planning. Although decisions to pursue mitigation are ultimately internal to an organization, managers and environmental staff will find it helpful to become knowledgeable about the environmental, technical, and political issues and influences that exist outside of their organization's boundaries. This information (provided in Chapter 2) assists in pinpointing the organization's specific reasons for mitigation GHGs. A clear understanding of these major motivations facilitates setting mitigation goals (Step 4), coming up with project ideas (Step 5), and evaluating mitigation alternatives (Step 6).

STEP 2: Create an inventory of baseline GHG emissions.

Quantifying the emissions baseline is essential information for the remaining planning steps. However, a utility can initiate this process before it has even decided to pursue climate change mitigation. Information about protocols for calculating GHG emissions inventories is provided in Chapter 3. For the target audience, the key suggestion is to use a more stringent and widely applicable protocol such as those published by the California Climate Action Registry (CCAR) or the GHG Protocol Initiative (see Section 9). By doing this, utilities will be well-prepared for receiving reduction credits or offsets, and for achieving compliance under future regulations that require inventory calculations.

The development of a detailed emissions inventory is often time-consuming. If this is the case, the mitigation planning process does not need to be put on hold. An easy-to-calculate, rough estimate of the emissions baseline will be sufficient for setting mitigation targets and identifying a utility's major sources of GHG emissions (that might also provide excellent mitigation opportunities).

STEP 3: Set goals (target amounts) for GHG mitigation.

Setting the mitigation goal is a necessary precursor to evaluating and selecting mitigation alternatives. As described in Section 3.2, certain considerations are helpful in deciding upon a mitigation goal and should include, though not necessarily be limited to, the following:

- GHG targets set under existing climate change policies and programs;

- Targets set by other organizations;
- The utility's motivation for mitigating GHGs; and
- Information from the inventorying process about mitigation opportunities.

Utilities currently have a great deal of freedom in setting their targets, so this guide strongly recommends selecting a goal that has significance for the utility and its stakeholders.

STEP 4: Identify relationships for collaborative mitigation activities.

The identification of potential relationships is an early step because the opportunity to collaborate on mitigation projects will usually increase the options available to a small municipal utility. Projects that are too large for independent, direct implementation potentially become feasible with multiple investors. Although there are no set 'rules' for this step, a logical approach is to initiate discussions and inquiries with other municipal utilities and/or through existing business relationships. If potential collaborations are identified, the utility should coordinate with these other organizations as early as possible during the planning process, and encourage them to begin their planning steps as well. In addition to establishing guidelines for the relationship, early coordination provides information about each organization's goals and mitigation capabilities. This information will define boundaries for generating the list of mitigation alternatives (Step 5).

STEP 5: Delineate and categorize a list of mitigation alternatives.

This is the idea-generating part of the process. Although managers/staff might have a specific mitigation activity in mind at the start of the planning process, it is strongly recommended that they take the time and sincere effort to develop a comprehensive list of alternatives. This will benefit them in two ways. First, in generating the list of alternatives, they may discover that better performing options are available. Second, in the process of evaluating the alternatives, managers will be taking the board of directors' concerns into account. It will be far easier to garner support from these stakeholders for a mitigation alternative if the utility can show that it has thoroughly and systematically considered its other options and can justify the selection(s) that it has made.

One approach to idea-generation is to hold a (series of) structured brainstorming session(s) involving managers who are broadly familiar with the organization's various facilities and operations and a consultant that specializes in GHG mitigation for the business community.

Regardless of how the list is generated, the participants will need to have knowledge of the basics of climate change, greenhouse gas mitigation options, potential roles for utilities in solving the problem and climate change policy setting. They will also need to have a clear understanding of the utility's motivation(s) for mitigating GHGs. Sources of information for idea generation that should be compiled and reviewed prior to creating the list of alternatives include:

- The utility's major direct and indirect emissions (Taken from the inventorying process);
- Existing energy conservation/efficiency programs that have the potential for expansion;
- Information about Renewable Portfolio Standards in California;
- Information about potentially major GHG sources at local and regional levels (For example, dairy farms or landfills in California with potential for methane capture projects); and
- Examples of mitigation activities by other organizations with similar profiles. (For example, Sacramento Municipal Utility District, Seattle City Light Municipal Utility).

If mitigation activities are collaborative, this idea-generation step should also include a collaborative brainstorming session with knowledgeable managers from partner organizations. The same types of information (listed above) will assist this process (but information sharing will be limited somewhat by confidentiality requirements).

In the process of coming up with mitigation alternatives, the utility should do the following:

- Generate ideas from the inside out. Begin by considering options within the organization to reduce direct, onsite emissions. Next, examine the potential for reducing the organization's indirect emissions sources. Finally, consider options that are further removed from the organization. Focus on high-performing mitigation approaches (e.g. efficiency improvements and renewable energy transitions). This does not mean that other, potentially riskier options should not be included in the list, but the utility should ensure that the idea-generation process has not missed any high-performing possibilities;
- For a collaborative project, focus on specific opportunities that leverage the combined resources of the partner organizations;
- Do not consider options that have been eliminated by preliminary screening criteria in Chapter 40;
- Before wrapping up the idea-generation process, make sure that the way that each alternative is expected to mitigate GHGs has been briefly, but clearly, articulated;
- Categorize the alternatives by the type of mitigation they represent; and
- Describe how alternatives would be implemented (e.g. independent project, collaborative project, investment opportunity, or credit purchase).

STEP 6: Evaluate the alternatives and select one or a set of the alternatives.

This step begins with a first-pass consideration of the utility's list of mitigation alternatives using key evaluative criteria from Chapter 5 to flag any significant problems. Specifically, a utility should be aware of the following issues:

- A mitigation activity might not have additionality;
- Quantification and/or monitoring may be extremely difficult, if not impossible (as the project is currently envisioned);
- A high likelihood of leakage and permanence problems exists (especially for land-based sequestration projects);
- CPT estimates for the approach make it impractical as a means of achieving the organization's mitigation goals; and
- The alternative fits poorly with the overarching business vision, and is expected to be received poorly by the utility's stakeholders.

If alternatives raise these flags, look for ways to modify them to resolve the issues. This is where outside expertise is especially helpful. A consultant with experience in mitigation project planning/implementation will be able to offer suggestions on how to improve the potential alternatives. However, if overcoming one or more of these problems is not possible, remove these alternatives from the list.

The next part of this process – prioritizing the remaining alternatives – requires additional basic data gathering and calculations. Again, this is where an outside consultant can be helpful. If precise values are not available, utilities should consider making rough estimates of the following attributes for each alternative:

- Project baseline emissions
- Accuracy and availability of quantification and monitoring techniques
- Permanence of the mitigation (i.e. potential for retransmission of GHGs to the atmosphere)

- Likelihood of GHG leakage (i.e. GHG emissions outside of project boundary due to the project)
- Projected amount and timing of GHG mitigation
- Expected non-monetary ancillary impacts (derived from a scaled-down EIA process)
- Costs (e.g. project design, capital equipment, QMV) and expected project revenues
- Indications of acceptability under future climate change regulations
- The possibility for collaborative projects through existing business relationships
- Potential positive and negative stakeholder or public perception issues

This compiled information will produce attribute summaries for each of the alternatives which will facilitate the next process – comparing the alternatives based on the evaluative criteria from Chapter 5. Prioritize the options within each category (e.g. according to expected costs, ROI, baseline calculation requirements, QMV factors, permanence, etc…). For certain criteria (e.g. costs, project magnitude), the ranking of alternatives may be obvious. However, for other criteria (e.g. ancillary impacts, permanence, regulatory acceptance), prioritization is more difficult, if not impossible. To overcome this obstacle, use broad classifications. For example, instead of trying to explicitly rank project alternatives based on permanence considerations, divide them into basic categories of "fully permanent mitigation," "some impermanence (retransmission) possible," and "impermanence (retransmission) definite."

At the end of this process the utility will have a matrix containing the mitigation alternatives and their performances similar to that shown in Appendix A. The value of this matrix in comparing the options depends upon the quality of the information that has been gathered and the attention given to evaluating the alternatives for each criterion.

The decision of which mitigation alternative(s) to pursue should reflect the following:

- Implementing the (set of) alternative(s) expected to meet mitigation targets set by the utility;
- The alternatives performed best based on the evaluative criteria; and
- The alternatives are reflective of the organization's original motivations for mitigating GHGs.

STEPS BEYOND:

The steps described above only take the utility through the primary mitigation planning phase. After settling on mitigation activities, utilities will fully develop the project design and conduct pre-construction planning, including items such as: project siting, timeline development, financing, contractor selection, baseline estimation, ex ante quantification of mitigation, development of the monitoring and verification plan, and more. This is then followed by construction (if applicable), implementation and ongoing monitoring of the mitigation activities.

Throughout the Steps Beyond phase, utilities should be prepared to revisit their mitigation plan to accommodate:

- Changes within their organizations (e.g. a jump in power demand from customers);
- Changes in the regulatory and business settings (e.g. regulatory limits on emissions, new emissions reductions, or offset trading opportunities); and
- Developments in the field of GHG mitigation that alter the performances of different options (e.g. newly available robust, accurate and inexpensive quantification and monitoring techniques)

Utilities need to recognize that mitigation planning is an iterative process and that the utility must remain flexible enough to respond quickly to new situations.

Table 7. Mitigation planning process. Shaded boxes describe processes for each step. Yellow boxes are processes that a utility can readily do on its own. For processes in green boxes, utilities will benefit from involving outside expertise.

STEP 1: Establish desire & motivation to mitigate GHGs	Become knowledgeable about the following: • Problem of GHG emissions and climate change (§2.3 -§2.4). • Role of utilities in causing /addressing the problem (§2.5). • Other utilities' mitigation activities (§2.5.4). • Regulations and policy (§2.6-§2.7).
STEP 2: Create an inventory of baseline GHG emissions	• Choose and implement an inventory protocol stringent enough to satisfy future regulations (§3.1). • If inventorying takes considerable time, create a rough emissions estimate to facilitate the next planning steps.
STEP 3: Set goals (target amounts) for GHG mitigation	To decide on a goal, review: • Organization's baseline emissions estimate(§3.2 -§3.3). • Organizational motivations for mitigating GHGs. • Mitigation goals set by other utilities and businesses (§3.4). • Targets set by existing climate change policies (§3.4).
STEP 4: Identify relationships for collaborative mitigation projects.	• Identify organizations (especially within the utility sector) with potentially similar mitigation goals (§2.5.4)). • Coordinate with other organizations if common interests exist in implementing a project.
STEP 5: Delineate and categorize a list of mitigation alternatives	• Use Figure 8.3 to guide idea generation (§7.3). • Use a brainstorming process and mitigation options presented in Chapter 5 for further idea generation. • Consider the following idea sources: o Utility's & partner organizations' in-/direct emissions o Major GHG sources at local /regional levels o Existing energy conservation/efficiency programs o Renewable Portfolio Standards opportunities. • Do not consider options eliminated in preliminary screening (Chapter 4).
STEP 6: Evaluate the alternatives and select one or a set of the alternatives	• Use the evaluative criteria in Chapter 5 to identify problems that make options unsuitable. Alter or remove these. • Use the evaluative criteria to compare expected performances of selected mitigation options (Chapter 6). This can involve making rough estimates of the following: o Costs (e.g. project design, capital equipment, QMV) o Project baseline emissions, leakage, permanence issues o Projected amount and timing of GHG mitigation • Select a set of options that can meet mitigation targets and perform best based on the evaluative criteria.

8. Specific recommendations for Burbank Water and Power

This chapter takes the reader through the mitigation planning process for BWP (Section 8.1) that was laid out in Chapter 7. It is essential the reader recognize that none of the steps can be *fully* completed for BWP by the authors of this guide. However, this chapter will specifically guide BWP through the process, and help other readers more clearly envision what the process involves as well as possible outcomes of each step. Section 8.2 provides cost ranges for mitigation options that were discussed in Chapter 6 (not including options that were screened out in Section 8.1.5). Note that these costs reflect 2005 dollars and will change as technological developments progress. Section 8.3 steers utilities toward better performing options by providing general recommendations in the form of a prioritization guide. Finally, the recommendations provided for BWP and the mitigation planning process are briefly summarized in Section 8.4 to provide a final overview of the role of the Guide.

8.1. Option Selection Process for Burbank Water and Power

8.1.1 BWP STEP 1: Establish desire and motivation to mitigate GHGs

By requesting this guidance document, BWP has already demonstrated its desire to mitigate its impact on climate change. However, BWP should determine its motivations. Based on communication with BWP managers and environmental staff, potential drivers of their interests appear to include:

- Desire to continue acting as an environmental leader and innovator among municipal utilities;
- Concerns about being prepared for future carbon constraints that will limit business options; and
- Opportunities to generate revenues or reduce costs through mitigation efforts.

At this stage, BWP needs to recognize the full list of its motivations and rank them according to importance to the organization. This will help BWP in subsequent planning steps such as setting a mitigation goal and evaluating different mitigation options. Furthermore, a clear articulation of its motivations will help BWP garner support from its stakeholders and potential collaborators.

8.1.2 BWP STEP 2: Create an inventory of baseline GHG emissions.

BWP is in the process of generating a thorough GHG emissions inventory with the CCAR. To facilitate subsequent planning steps, a rough estimate of BWP's emissions was made (see sections below). Direct BWP emissions are approximately 25,085 MTCE and indirect emissions are approximately 137,641 MTCE averaged for calendar years 2000, 2001, and 2003. BWP's total GHG liability is therefore 162,731 MTCE per year.

A rough calculation of BWP's emissions based on a portion of the California Climate Action Registry (CCAR) protocol and consideration of only BWP's major stationary emission sources is provided below. An evaluation of current initiatives undertaken by BWP that potentially mitigate atmospheric GHGs follows .

Assessment of BWP's emissions

Utilities need to inventory their emissions to facilitate setting a GHG mitigation goal and identifying abatement opportunities. They should initiate the inventory process (using one of the protocols described in

Section 3.1) early in their mitigation planning. However, collecting the data for this detailed inventory can be time-consuming, and a utility may wish to move forward with developing its mitigation plan in the meantime. If this is the case, utilities should still calculate a less detailed estimate of its emissions to facilitate setting a mitigation goal, identifying potential abatement opportunities (e.g. efficiency improvements within the organization), and evaluating mitigation options.

This section takes the reader through the process of making a rough estimate of organizational emissions using BWP as an example. For this analysis two major emissions source categories were identified and included:

- Direct emissions from BWP's major stationary sources; and
- Indirect emissions through purchase of energy from the Intermountain Power Project (IPP)

There are two estimation methodologies available to calculate a utility's GHG emissions: (1) emission factors (in conjunction with fuel use or generated electricity) and (2) direct monitoring. Most GHG registries use an emissions factor-based methodology for estimating GHG emissions. Some registries accept direct monitoring data from utilities equipped with a Continuous Emission Monitoring System (CEMS) that monitors CO_2 pursuant to applicable regulations. Utilities should be forewarned that for some protocols, costly data sources such as CEMS become required for subsequent inventory submittals once used for initial reporting purposes (CCAR, 2004). Specific estimations methods are developed by each registry. However, to facilitate trade programs and technology development, there is considerable interest in ultimately combining both types of estimation methodologies (Keith, Biewald, and Sommer, 2003).

In the following sections, BWP's emissions are compiled using an emissions factor-based method. Due to complications inherent in calculating non-CO_2 GHG emissions (e.g., CH_4 and N_2O) resulting from fossil fuel combustion, the following rough estimate considers only CO_2 emissions. This is a reasonable approach because CO_2 makes up 10-12% of the exhaust stream whereas other GHG compounds make up less than 0.1%.

Direct stationary source emissions

BWP's direct stationary emissions were derived by taking an average 1-year baseline inventory of fuel use. Individual emission units considered in the baseline were:

- Two natural gas-fired boilers rated at 44 and 55 MW; and
- One natural gas-fired turbine rated at 46 MW.

In order to evaluate GHG emissions using a representative baseline, calendar years 2000, 2001, and 2003 were utilized. Year 2002 was omitted as unusually low operation of the two boilers was due to retrofitting the units with non-GHG emission control devices. It should be noted as well that the two boilers' total fuel use for 2003 was offset with the higher efficiency turbine that was brought online in December 2002.

The primary emission factor used to derive direct stationary emissions was based on historically estimated CO_2 emissions per amount of fuel used (lbs of CO_2 per thousand cubic feet (kcf) of fuel). The derived factor was 120.6 lbs/kcf. As a quality check mechanism, this derived emission factor was compared to a generic emission factor (121.6lb/kcf) provided by the GHG Protocol Initiative. The percent difference between the two was quite small (0.8%). Information sources and conversion factors are noted in Table 8.1.2. Emissions estimated from direct sources were 92,908 metric tons (MT) of CO_2 (25,085 MTCE), $\pm$ 8.4 percent calculated uncertainty. The emission estimate spreadsheets are provided in Appendix B.

Table 8.1.2.a. Emission and process factors used for BWP emissions estimate

Source	Factor Description	Units	Derived factor
GHG Protocol Initiative	CO_2 emission factor (natural gas)	lbs / kcf	121.6
EIA	CO_2 Emission Factor (Utah Bituminous Coal)	lbs / MMBTU	204.1
IPP	Average Heat Rate of Utah Coal	BTU / kWh	9517.0
GHG Protocol Initiative	CO_2 Emission Factor (National Average 1988-2000 for coal) [QA/QC]	Grams / kWh	932.0

Indirect stationary source emissions

BWP's indirect stationary emissions were derived by estimating emissions associated with power that BWP purchases from Intermountain Power Project (IPP), a two-unit (each 950 MW gross capacity) coal-fired power plant in Utah (BWP, 2003; IPP, 2003). BWP has an annual 3.371% interest (i.e. 69 MW) in IPP. Emissions were estimated by taking an average 1-year baseline inventory of fuel use for fiscal years 2001, 2002, and 2003. Monthly fuel use data was unavailable, thereby negating temporal consistency with the direct emissions baseline. It was assumed that the IPP was fired exclusively on bituminous coal. This assumption is based on IPP use of Utah-mined coal (IPP, 2003), and an EIA report noting that only bituminous coal is mined within Utah (EIA, 1999).

Two emission factors were used for comparison: (1) a heat-content based emission factor and (2) an electricity-generated based emission factor (Table 8.1.2.a). Both factors were derived using a combination of information from IPP, BWP and the GHG Protocol Initiative. The 5.4% difference the methods is likely due to the electricity-generated based factor is a national average of all coal types; bituminous coal is the primary coal mined in Utah and has a lower carbon content than other coals used within the U.S. (EIA, 1999). However, for a conservative estimate, the larger of the two results was used for analysis purposes (509,804.0 MT CO_2 or 137,647.1 MTCE) $\pm$ 8.4% calculated uncertainty. The emission estimate spreadsheets are provided in Appendix B.

Assessment of existing BWP GHG mitigation measures

Municipalities such as BWP have a number of opportunities to reduce GHG emission liabilities. Of particular interest are projects that serve at least one additional benefit beyond accomplishing GHG emission reductions. Some technology strategies for reduction of GHG emissions may result in reductions of criteria pollutants. For example, reductions in CH_4 emissions would result in a simultaneous reduction of volatile organic compounds (VOCs). Policies implemented to improve energy efficiency would reduce all pollutants as less fuel is used per unit of generated electricity (for generation-side improvements) and less electricity is demanded (for consumer-side improvements). Renewable Portfolio Standards provide a means to procure energy from sources that are free of GHG emissions (e.g., wind farms, solar arrays, and hydro). However, EPA Guidance documents regarding the crediting of renewable energy and energy efficiency projects caution that claimed reductions are required to meet the same criteria of surplus, real, verifiable, and permanent as traditional projects. This caveat is specific to sources that import energy from other pollutant sources (EPAe, 2004). To date, BWP has implemented a number of these types of projects that are summarized in Table 8.1.2.b.

Table 8.1.2.b. BWP-Implemented GHG Emission Reductions

Project	Type of Mitigation	Project GHG Benefit
Capstone Turbines for landfill methane recovery and energy generation (550kw)	Renewable [a]	• Mitigation of fugitive CH_4 emissions • Displaces energy purchase/generation from non-renewable sources
Hydrogenerators at Valley Pumping Plant (1000 MWh generated annually)	Renewable [a]	• GHG-free energy generation • Displaces energy purchase/generation from non-renewable sources
Solar Water Heating at McCambridge Park Pool	Renewable [a]	• Displaces energy purchase/generation from non-renewable sources
Public Electric Vehicle Charging Locations	Renewable [a]	• Displaces use of fossil fuels for project combatable vehicles
Clean Green Program	Renewable [a]	• Investment opportunity for BWP customers to purchase renewable energy
Fluorescent Bulb Distribution	Efficiency [a]	• Decreases demand for electricity
Made in the Shade	Efficiency [a]	• Decreases demand for electricity
Alternative Fuel Vehicle Fleet	Efficiency [a]	• Displaces use of fossil fuels for project combatable vehicles
Energy Solutions Program	Efficiency [a]	• Gives business customers incentives to invest in renewable energy and energy efficiency measures
Home Rewards Rebate Program	Efficiency [a]	• Gives residential customers incentives to invest in energy efficiency appliances and technology
Home Energy Analysis	Outreach/ Awareness	• Promotes energy efficiency and conservation practices

a – See text discussion for a caveat to use of this category

8.1.3 BWP STEP 3: Set goals (target amounts) for GHG mitigation.

Once a GHG emissions inventory is generated, a mitigation or reduction goal must be set. In the absence of mandated regulatory reductions, BWP has great deal of flexibility in setting its targets. As described in Section 3.2, this guide recommends at a minimum, compliance with the requirements of the Kyoto Protocol: a 7% reduction in GHG emissions from 1990 levels. Since BWP's 1990 emissions data is not available, it is assumed that BWP's electricity generation and distribution has remained relatively constant and therefore, compliance with the Kyoto Protocol would require a reduction of approximately 11,400 MTCE per year.

8.1.4 BWP STEP 4: Identify relationships for collaborative mitigation projects.

A few relationships were identified for BWP that might provide opportunities to collaborate on mitigation activities.

- The Southern California Public Power Authority (SCPPA) (BWP and other member utilities participate in power projects through SCPPA);
- Los Angeles Department of Water and Power (LADWP) (BWP already coordinates directly with LADWP on energy and water projects); and
- Intermountain Power Project (IPP) in Utah. (BWP is a minority stakeholder in this project.)

At this stage, BWP needs to develop a comprehensive list of relationships, determine which organization(s) are likely collaborators and coordinate with them on idea generation and evaluation of the alternatives.

8.1.5 BWP STEP 5: Delineate and categorize a list of mitigation alternatives.

Once a mitigation or reduction goal has been set, BWP will generate a list of potential mitigation options. Several viable alternatives that BWP can choose to pursue are presented here to illustrate the brainstorming process. These recommendations provide a good overview of projects that can be implemented by BWP but is by no means a comprehensive list.

Brainstorming of mitigation options for BWP:

- **Onsite Direct Emissions Reductions**
  - Forego use of older, less efficient steam boilers (Olive 1 & 2) to meet peak demand. Limit use to Lake One and Magnolia Project gas turbines.

- **Offsite Direct Emissions Reductions**
  - Collaborate with SCPPA to invest in a wind power project

- **Offsite Indirect Emissions Reductions or Offsets**
  - Collaborate with IPP to upgrade boilers for integrated gasification combined cycle technology.
  - Collaborate with IPP or larger consortium such as SCPPA to create a geological sequestration project near IPP.

- **Offsite Emissions Offsets**
  - Invest in methane capture at a dairy farm within California.
  - Purchase credits from Chicago Climate Exchange to offset indirect emissions from IPP.

Table 8.1.5.a. summarizes major characteristics of some mitigation options that would be feasible for BWP to implement.

Project	Project location	Type of Mitigation	Mitigates by:	Implementation
Olive 1 & 2 shut down	Onsite	Energy efficiency	Direct emission reductions	Independent project
Wind farm power project	Offsite	Renewable energy transition	Direct emission reductions	Collaborative project
IPP boiler modifications	Offsite	Energy efficiency; Industrial process modification	Indirect emissions reduction	Collaborative project
IPP geological sequestration	Offsite	Geological sequestration in a saline aquifer	Indirect emissions reduction or emissions offset	Collaborative project
Dairy farm methane capture	Offsite	Methane capture and use	Emissions offset	Independent or collaborative project
Purchase of CCX credits	Offsite	Not applicable (credit purchase)	Emissions offset	Independent project

Preliminary screening

When brainstorming potential mitigation options for implementation, BWP should avoid certain types of options that did not meet the Preliminary Screening Criteria. Preliminary screening criteria for eliminating unsuitable mitigation options were described in Chapter 4. These three criteria are:

- Commercial implementation of the approach by the utility is currently feasible (Section 4.1);
- The approach is relatively certain with respect to its efficacy for mitigating GHGs and/or the low possibility of negative ramifications that cause net harm to human health or the natural environment relative to the status quo (Section 4.2); and
- Existing and pending policies and regulatory frameworks *do not* explicitly indicate that a mitigation approach is unacceptable (Section 4.3).

Any mitigation options that could not meet one or more of these criteria are immediately removed from the pool of mitigation options. Out of the broad categories of options listed in Table 6, four are filtered out at this time: ocean injection, mineral carbonation, ocean seeding and biomass to product approaches. The reasons for eliminating these options are described in detail below. Table 8.1.5.b. lists the remaining options that fulfill these suitability criteria and provided the foundation for developing a list of possible mitigation projects that could be pursued by BWP.

Table 8.1.5.b. Remaining mitigation options.

Reduction	Sequestration	Use
Industrial process modifications	Forest sequestration	Methane capture (landfills; livestock manure)
Renewable energy transitions	Agricultural sequestration	Bio-mass to energy
Efficiency improvements	CO_2 injection into geological formations	

Mineral carbonation

Development of mineral carbonation techniques is still in the research phase. Implementation at a commercially viable and environmentally beneficial level to mitigate atmospheric GHGs is not currently possible. In nature, the mineral carbonation conversion is exothermic and spontaneous, but the reaction rate is far too slow for a commercially viable process. To bring this approach to market, research is focused on increasing the reaction rates. These optimization efforts are constrained by the thermodynamics of the reaction and at this time, there is "insufficient knowledge to conclude whether a cost-effective and energetically acceptable process will be feasible" (Huijgen & Comans, 2003). As a result of these efficacy issues, mineral carbonation is not a suitable mitigation option at this time.

Ocean injection

Laboratory simulations of ocean injection processes have been conducted, and, theoretically, injections of CO_2 is technologically feasible because equipment requirements are similar to those used in the petroleum industry. However, "few direct, oceanic experiments have been reported" (DOE, August 2003b). Furthermore, the U.S. Climate Change Technology Program points out that "there is insufficient data detailing hydrate interactions with marine community structure, as well as knowledge gaps about physical and chemical behavior concerning dispersion and transport of hydrate plumes by ocean hydrology" (US-CCTP, 2003). Research on these issues of marine environmental impacts and behaviors of CO_2 plumes in the ocean is ongoing, but it lags behind terrestrial sequestration research. Due to the environmental uncertainties and lack of practical implementation examples, ocean injection is not a suitable option at this time.

Ocean seeding

Unlike ocean injection and mineral carbonation, implementation of ocean seeding can already be achieved on a commercial scale. Furthermore, in terms of an economic evaluation, this approach can be cost-effective if the predicted levels of sequestration could be achieved. However, this approach has high levels of uncertainty with respect to its efficacy for sequestration of CO_2. In addition, potentially extreme negative environmental ramifications of this method exist. Factors such as limiting nutrients, vertical transport, remineralization rates, and sunlight availability control the successful sequestration of CO_2 that is captured due to ocean fertilization. Poor understanding of these factors creates difficulties in quantifying the true amount of carbon equivalents that are removed permanently from the atmosphere (Buessler, 2003). At this point, researchers cannot assert that ocean seeding is a useful abatement approach. Of greater concern are the environmental uncertainties associated with stimulating primary production across a wide area of ocean. Impacts could include changes to ocean species compositions, reduced light penetration, release of byproduct GHG (e.g. N_2O) and changes to the marine layer atmosphere (Chisholm, Fallowski, Cullen, 2001; Lawrence, 2002).

Biomass to product

Biomass to product (BTP) options in which CO_2 is captured in plant matter (e.g. trees) and stored in a long-lived product are commercially feasible. However, it is not possible to perform accurate quantification, monitoring and verification of achieved GHG mitigation from these projects. This problem is inherent to BTP projects because the project owner does not retain control over the long-term carbon sink that is providing the GHG offset. Existing climate change policies require some means of measuring the performance of a project. In the future, these policies might be amended with guidelines for these steps of a BTP project. This would enable a utility to establish the number of offsets it has achieved with a project and, in turn, facilitate compliance with a climate change regulation, and/or the terms of a trading system. However, without these clear compliance guidelines, BTP projects that rely on long-term storage of the carbon in the product are currently unsuitable approaches for a utility.

The second type of BTP project involves substituting biomass for fossil fuel-based feedstock material in the production of short-lived commodity chemicals (e.g. biopolymer plastics). As described previously, GHG abatement benefits have not been demonstrated with these projects (Kurdikar, et al., 2001). Although more efficient production techniques that might facilitate mitigation are on the horizon, application of BTP options for this purpose requires more time for development (Lynd and Wang, 2004). As a result, this second form of BTP mitigation is also currently unsuitable.

8.1.6 BWP STEP 6: Evaluate the alternatives and select one or a set of alternatives.

Once all the alternatives have been laid out, the utility must now use the evaluative criteria set forth in Chapter 5 to choose the mitigation option(s) that will achieve their goals. This is a two-step process of elimination. The first pass involves a rough comparison of a subset the evaluative criteria and identification of knowledge gaps for the alternatives being compared. As an example, the performance of our recommended mitigation alternatives, based on these criteria, are compared in Table 8.1.6.a. The second pass involves a more detailed look at each mitigation alternative and their attributes. Since many of these evaluative criteria are project-specific (that is, based on how the project is sited and designed), we are not able to execute this step. However, we follow the table with a more detailed discussion of the mitigation alternatives that are recommended as viable projects for BWP to implement or further investigate.

Table 8.1.6.a. presents a comparison of five evaluative criteria for mitigation options chosen for BWP.

Project	Can establish baseline?	Addition-ality?	QMV	Permanence	Leakage?	Additional benefits
Olive 1 & 2 shut down	YES	YES	YES	Fully permanent	NO	Reduce operating costs; Reduce criteria pollutants
Wind farm power project	YES	YES	YES	Fully permanent	POSSIBLE	Reduce operating costs; Reduce criteria pollutants
IPP boiler modifications	YES	YES	YES	Fully permanent	NO	Reduce IPP operating costs; Reduce criteria pollutants
IPP geological sequestration	YES	YES	Diffic ult	Not fully permanent	POSSIBLE	Large sequestration capability
Dairy farm methane capture	YES	YES	YES	Fully permanent	NO	Source of renewable energy
Purchase of CCX credits	N/A	N/A	N/A	N/A	N/A	None

Olive 1 and 2 shut down

With the impending start-up of the Magnolia Project gas turbine and in conjunction with Lake One turbine operations, one GHG mitigation option for BWP is to forego future utilization of the Olive I and II steam boilers. Shifting peak demand use from these less efficient units to the more efficient natural gas-fired turbines will result in GHG emission reductions of 2.5% for every 1% gain in efficiency. Estimated GHG emission reductions caused by shutting down the wall-fired Olive I boiler (estimated to be 27% efficient) range from 18.8 to 48.8% (4,716 – 12,242 MTCE), depending on the percent of energy generation reallocated to Lake One turbine (estimated to be 34.5% efficient) and Magnolia combined cycle turbine (estimated to be 46.5% efficient). Estimated GHG emission reductions by shutting down the turbo-fired Olive II (estimated to be 31% efficient) range between 8.75 – 38.8% (2,195 – 9,733 MTCE), depending on percent reallocation to Lake One and Magnolia turbines. Taking the median percent reduction in direct GHG emissions of 28.8%, BWP can realize 4.4% reductions of combined direct and indirect GHG emissions inventory as derived in Section 3.2. Non-GHG mitigation benefits include decreases in regulated air pollutants and operational costs by way of reduced fuel consumption. As discussed in Section 7.2, it is most cost effective to pursue reductions of onsite direct emissions reductions.

Wind Farm Power Project

Wind power is clean, renewable, economically competitive, and contributes to direct emissions reductions. There are many available locations for siting wind farms, and great flexibility exists in project size (e.g. beginning implementation with only a few wind turbines). The DOE has developed a brief guide on wind power development for municipal utilities which contains case studies, economic information, and an overview of the benefits of wind farm projects (DOE, 2002b). The DOE estimates that a 750 kW project would cost $800,000 in working capital and startup costs (O&M costs are not included). This project, enough to serve the annual needs of more than 250 households, would generate between $80,000 and $100,000 worth of electricity each year. The project could also take advantage of federal funding through the Renewable Energy Producer Incentive (REPI) that provides 1.8 cents per kWh in financing for municipal utilities. This would provide additional revenue of $35,000 per year. Over a 10 year period, non-discounted revenue would be $1.15 to $1.35 million. A project executed on a larger scale could be feasible and profitable with the involvement of other SCPPA utilities.

The revenues and costs from an energy project can be translated into avoided emissions and CPTs through emissions factors. Below, Table 8.1.6.b. takes the earlier figures from the DOE's guide, and uses an emissions factor to estimate the cost per ton. The power of the 750 kW turbine is multiplied by the number of hours per year (8760) and converted into potential kWh of energy. However, wind turbines only have an efficiency of about 40% (DOE, 2005d; Altera Energy, 2004). The resulting capacity is then multiplied by the emissions factor of the fuel it is replacing. This yields an estimate of the number of metric tons of emissions avoided per year.

The cost per ton (of emissions avoided) can then be calculated using relevant financial information. The CPT estimated in Table 8.1.6.b was calculated by totaling the annual revenue from electricity sales and REPI then subtracting the annual working capital and startup costs, over 10 years. A conservative estimate of $80,000 in annual revenue from electricity sales was used (DOE, 2002b). As in the previous scenario, O&M costs are not included. The cost per ton estimate shows the cost-effectiveness and competitiveness of a wind turbine compared to steam boilers and process modifications. This type of chart can be used to examine the feasibility of other renewable energy projects as well.

Table 8.1.6.b. An estimate of annual emissions and cost per ton for a single wind turbine.

Process	Value	Units	Notes
Wind turbine size	750	kW	Source: DOE, 2002b
Total energy (turbine size x 8760 hours)	6,570,000	kWh	Operating hours per year
Efficiency	40%		Source: DOE, 2005d; Altera Energy, 2004
Capacity	2,628,000	kWh	Total energy x Efficiency
Emissions factor (using Utah Bituminous coal)	0.32	kg C / kWh	Source: EIA, 1994
Total emissions avoided	832,105	kg C	Capacity x Emissions factor
Total emissions avoided	832	MTCE	1 MT = 1000 kg
Annual operating cost (10 year project life)	-$35,000	USD	Source: DOE, 2002b
Cost per ton of C	-42	$/MTCE	Annual, over 10 year period
Cost per ton of CO_2	-11	$/MT$CO_2$E	1 ton C ~ 3.67 tons CO_2

IPP boiler modifications & saline aquifer sequestration

The main sources of BWP's GHG liability are the emissions associated with the IPP's coal-fired power plant. Due to the lack of specific information on IPP's technological capabilities, we only provide a general discussion of its industrial process modification and geological sequestration capabilities.

Upgrading combustion technology to the more fuel efficient integrated gasification combined cycle (IGCC) technology will significantly reduce GHG emissions, thus reducing BWP's indirect emissions, and decrease operational costs for IPP by reducing capture and separation costs associated with exhaust CO_2 capture (as mentioned in Chapter 6).

The possibility of investing in a geological sequestration project with IPP is mentioned because of extensive carbon sequestration projects being undertaken within the Colorado Plateau. The Department of Energy's National Energy Technology Laboratory (NETL) is currently investigating the potential for CO_2 sequestration projects in saline aquifers within the plateau. A few of the sites being investigated are near Delta, UT where IPP is located (DOE, 2004a).

Dairy farm methane capture

According to the EPA AgStar Program, California has the highest number of dairy farms available for the implementation of biogas recovery systems (methane capture and use). A project at a 1000-cow dairy farm in California's Central Valley would reduce GHG emissions by approximately 1,075 MTCE per year and cost upwards of $200,000, involving the installation of an anaerobic digester and biogas capture device. The captured methane can then be used for electricity production. The AgStar Program is currently developing a publication entitled "Market opportunities for biogas recovery systems" which will identify candidate dairy farms, their potential for biogas recovery, and expected methane reductions of implementing a project. This publication is not currently available but will hopefully be ready for distribution by summer 2005. We recommend contacting the EPA AgStar Program to obtain more information about investing in dairy farm biogas recovery systems.

Purchase of CCX credits.

There are currently no federally-mandated trading mechanisms in place. The Chicago Climate Exchange (CCX) is a pilot credit trading program with members that voluntarily offset GHG liability through buying and selling of credits in this market. This option does not directly reduce BWP's GHG emissions nor does it provide additional, tangible benefits such as reduced operational costs. Yet, voluntary participation in a pilot trading mechanism may be an option that is favored by BWP's stakeholders. The credit trading organization is responsible for ensuring that GHG mitigation attributes such as baseline accounting, additionality, QMV capability, minimum leakage, and maximum permanence are accounted for in projects resulting in GHG mitigation. Therefore, a utility purchasing carbon credits must make certain that the credit trading organization is reputable and requires credited projects to address the four core attributes described in Section 5 of the guide. As of March 2, 2005, the market price of carbon at CCX is $1.60 per ton of CO_2, which is equivalent to $5.87/MTCE. To offset 9,000 MTCE through the purchase of carbon credits, it would cost approximately $52,805. This cost would vary through time and credits must be re-purchased each year.

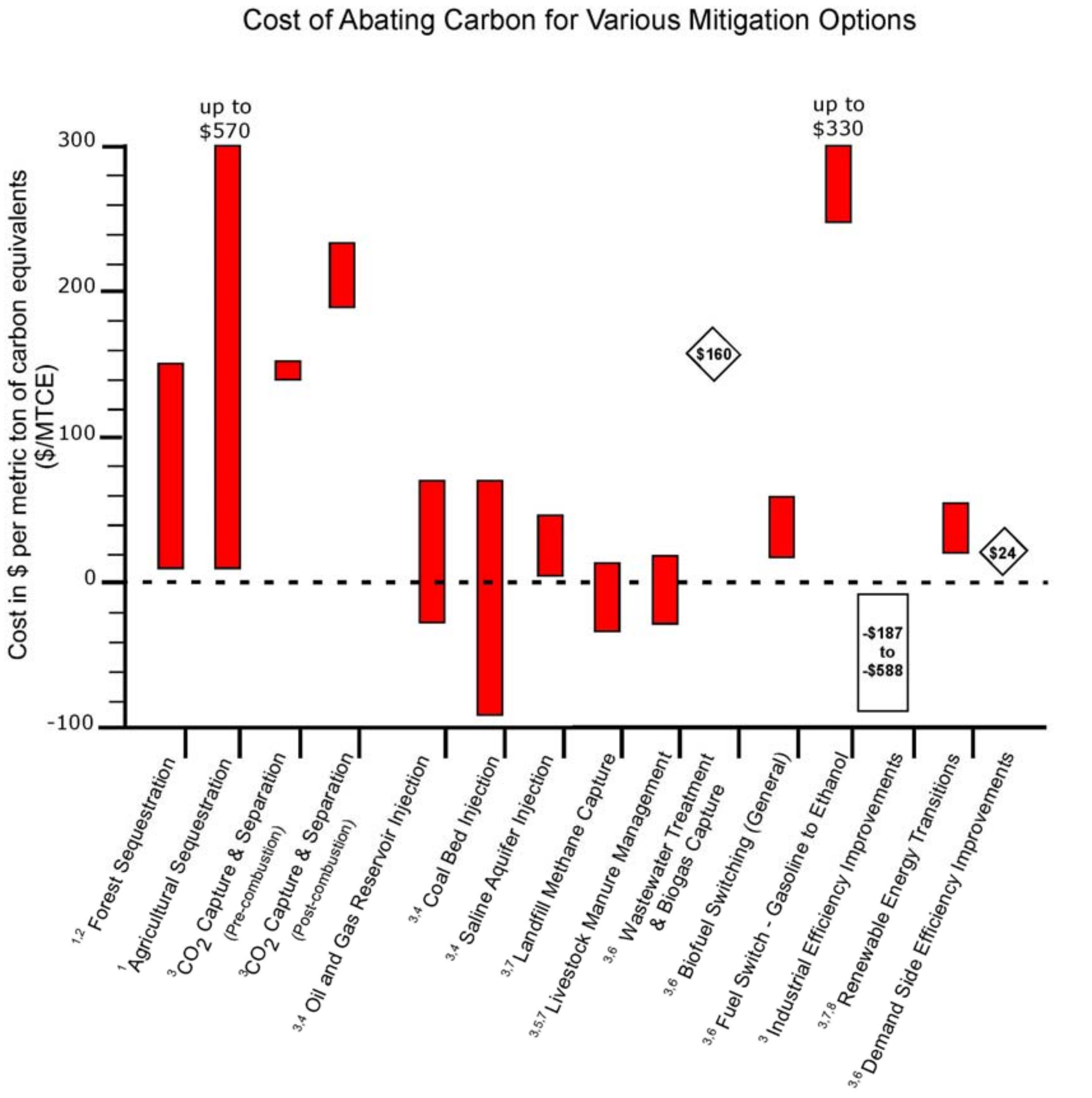
8.2. Evaluating costs of mitigation options

An efficient way to assess the remaining mitigation options in Table 8.1.5.b can be through cost per ton (CPT) estimates. However, a high level of variability exists in the reported CPT estimates for each mitigation option. The wide ranges in CPT values are due to differences in how a mitigation option is implemented (e.g. location, project size), and the cost assumptions and exclusions that are made in academic literature and reports from government and private projects. As a result of this variability, utilities should *not* use the exact, reported CPT values as decision factors. Rather, the reported values are useful as order of magnitude estimates of costs for making rough comparisons among options. Figure 8.2 illustrates the different mitigation cost ranges reported in reviewed and gray literature.

Utilities should also recognize that cost differences between mitigation options can arise from inherent disparities in mitigation kinetics. Some options such as forest and agricultural sequestration, require annualized

CPT calculations that span the project lifetime. Quantification of the biomass carbon in these projects is less straightforward because sequestration is not constant over the project lifetime. This is further complicate by permanence issues that must be factored into the calculations. Other mitigation options, such as geological sequestration, methane capture and use, and efficiency improvements usually have CPTs that are calculated based on a one-time working capital cost for construction of a facility (e.g. CO_2 capture plant, methane capture plant, or alterations to existing equipment) and the realized reductions in GHG emissions. These calculations are usually straightforward assessments of total project cost divided by the amount of GHG emissions reduced. Both categories have working capital, O&M and disposal costs, but agriculture and forestry options usually require additional levels of QMV and have a higher ratio of O&M to working capital costs.

Figure 8.2 Cost range to abate carbon for various mitigation options. Values were taken from review articles of mitigation costs when possible and converted to 2005 dollars.



Unless otherwise specified, costs apply to U.S. only, and project baseline estimate, quantification, monitoring and verification costs are *not* included.

[1]To sequester a specific amount of carbon in MMTCE annually.
[2]U.S. and global sequestration.
[3]Costs include one-time working capital costs only.
[4]Costs include capture and separation technologies.
[5]Based on calculation for a 500 head dairy farm.
[6]Costs derived from hypothetical estimates based on a case study.
[7]Includes O&M (operation and maintenance) costs.
[8]Costs pertain only to a portfolio containing 10% renewables.

8.3. Prioritizing mitigation options

Of the mitigation options not screened out by the Preliminary Screening Criteria, performance will vary based on the Evaluative Criteria outlined in Chapter 5. Some options will consistently be a better choice, while others may perform better based on the design of project parameters. Choosing a mitigation project will involve time and numerous resources for information-gathering. Options that seem optimal at first may not be so for the utility (due to its preferences, capabilities for implementation, etc.) upon closer inspection. Therefore, choosing and assessing mitigation options best suited for the utility is an iterative process. This section steers small municipal utilities towards better performing options through the use of the decision-making prioritization plan provided in Figure 8.3. The following general prioritization strategy is based, in part, on the discussion on alternatives for implementing mitigation actions provided in Section 2.5.2.

Preferred options for GHG mitigation are those which have the following features:

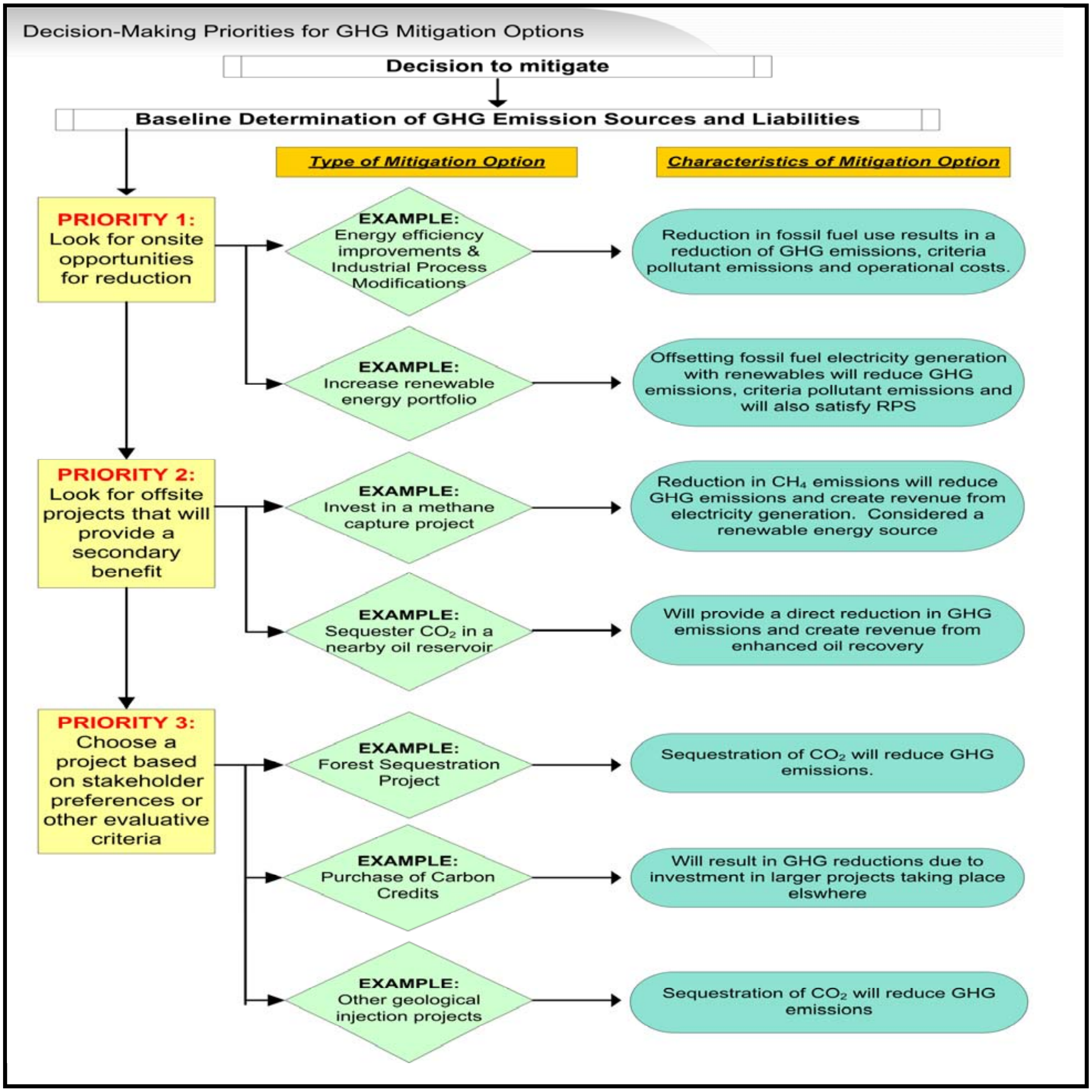
(1) can be executed onsite;
(2) immediately fulfill the four central evaluative criteria of project baseline and additionality, permanence, leakage, and QMV capabilities; and
(3) perform well in meeting the remaining criteria and/or criteria most important to the utility. Foremost among these are cost-effectiveness, provision of benefits beyond GHG mitigation (ROI), and ease of implementability by a utility.

With these preferred features in mind, onsite energy efficiency improvements, industrial process modifications, and renewable energy transitions (excluding biomass to energy) that reduce GHG emissions are identified as the primary GHG mitigation projects for utilities to pursue. For these types of mitigation, project baseline and additionality can be easily quantified and QMV capabilities are well-established. Emissions reductions are fully (100%) permanent and leakage is not an issue since the project is executed onsite. Options such as increased energy efficiency also result in multiple benefits beyond GHG reduction. Decreased fuel consumption will reduce operating costs and at the same time, decrease priority pollutant emissions. These types of projects are risk averse and easily implemented by a utility.

Once all cost-effective opportunities for energy efficiency, process modification and transitions to renewable energy have been exhausted, the next step is to look at offsite GHG mitigation options that meet the four central criteria described in Chapter 5 and provide additional, tangible benefits beyond GHG mitigation. Examples of mitigation options that fall under this second step include methane capture and use and oil reservoir sequestration. For example, oil reservoir sequestration is not fully permanent but will provide additional revenue from enhanced oil recovery. On the other hand, reductions achieved through methane capture and use projects meet all four core criteria; even though there is a release of CO_2 during combustion. In addition, investing in a methane capture project will not only reduce GHG emissions, but also provide a source of renewable energy generation. Likewise, many smaller projects, such as methane capture and use on landfills and dairy farms are economically viable for a small utility. On the other hand, larger projects such as the implementation of an oil reservoir sequestration project would require a partnership of several utilities for the option to be cost-effective.

Finally, if the above options have been implemented and do not achieve the desired mitigation goal, projects that meet the four core criteria to a lesser degree and provide fewer or no additional, tangible benefits beyond GHG reductions can be chosen. One viable alternative is the purchase of carbon credits through a carbon trading market such as the Chicago Climate Exchange (CCX). However, this may not be the most cost-effective solution as credits must be purchased yearly and the price is likely to increase in the future. Additional options that fall under this step include land-based sequestration projects, such as forest, agriculture, or geological sequestration. Land-based sequestration projects have inherent additionality, leakage, and permanence issues, which can be overcome with good project planning.

Figure 8.3. Structure for prioritizing mitigation options based on their overall performance under the evaluative criteria.



8.4. Summary & Conclusions

A mitigation plan need not be limited to the implementation of a single project. Rather, for BWP to effectively achieve its mitigation target, an assortment of GHG mitigation activities should be combined. A small municipal utility like BWP may be resource-limited and will therefore, need to prioritize which mitigation alternatives to pursue first.

Using the procedures presented in this guide, we have determined that for BWP to embark on an effective and cost efficient GHG mitigation approach, they should first concentrate on emissions reductions achievable through generation-side energy efficiency; consumer-side energy efficiency; and offsetting fossil-fuel combustion through increased renewable energy use. BWP has actively participated in many of these types of programs (as illustrated in Table 0.b) and should continue to adopt programs of this nature as the benefits far outweigh the costs of mitigating a comparable quantity of GHG emissions using other GHG-specific reductions strategies currently under development (from both an implementation and policy stance).

Additionally, BWP should look into cooperating with other municipal utilities on larger mitigation projects. The list of alternative projects that BWP can implement is greatly increased by participating in a consortium. One option is to take advantage of the SCPPA group that BWP is currently a part of. However, once a mitigation plan has been developed, BWP must keep in mind the importance of project siting and design to make sure the evaluative criteria, especially the four core criteria, for effective GHG mitigation are fulfilled.

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By following the GHG mitigation planning process described in Chapter 7, a utility will be able to navigate the complexities inherent in embarking upon GHG mitigation activities. We have included guidelines on which step in the planning process the information presented in Chapters 2-6 of this guide will be of most use and suggestions for when a utility may want to call in a consultant to facilitate the planning process. Once a utility has (1) familiarized itself with the GHG emissions and climate change problem; (2) created an inventory baseline; (3) set goals for GHG mitigation; and (4) identified potential collaborative projects, Section 8.3 will guide the initial qualitative idea-generation step (Step 5) for creating a list of mitigation options. This should then be followed up by a quantitative comparison of the potential mitigation alternatives using the evaluative attributes described in Chapter 5 (Step 6).

The latter part of the decision-making process (Steps 5 and 6) may need to be repeated several times depending on whether a utility is able to generate an adequate list of mitigation alternatives. Once the comparison step is completed, it is then up to the utility to pick an alternative(s) and implement the project making certain that the project design incorporates all the attributes necessary for a project to be considered a good GHG mitigation project.
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9. Resources & Contacts

CLIMATE CHANGE SCIENCE

The IPCC has published a series of comprehensive reports concerning climate change science and mitigation and adaptation strategies. The reports are based on peer-reviewed and published scientific/technical literature.
http://www.ipcc.ch/pub/reports.htm

CLIMATE CHANGE POLICY

The Pew Center on Global Climate Change was established in 1998 as a non-profit, non-partisan, independent organization. In addition to providing climate change research, the center works with policymakers and business leaders to create climate change solutions.
http://www.pewclimate.org/

The West Coast Governors' Global Warming Initiative was formed by the governors of CA, Oregon and Washington in September 2003 to develop state and regional strategies regarding global warming.
http://www.energy.ca.gov/global_climate_change/westcoastgov/index.html

MUNICIPAL UTILITIES

BWP is one of twelve members of the Southern California Public Power Authority (SCPPA), a municipal utility lobbying group. SCPPA's activities include operations and financing of joint power projects.
http://www.scppa.org/

The CEC was created by the CA Legislature and is CA's primary energy policy and planning agency. Its responsibilities include energy forecasting and technology, and energy efficiency and renewable energy.
http://www.energy.ca.gov/

The CA Public Utilities Commission (CPUC) is the regulatory body for CA's IOUs. The CPUC also works on RPS implementation.
http://www.cpuc.ca.gov/

IPCC STUDIES

The IPCC was created by the UN in 1988 to assess the scientific, technical and socio-economic aspects of climate change.
http://www.ipcc.ch/

METHODOLOGY

The CA Climate Action Registry (CCAR) was established by CA statute as a non-profit, voluntary registry for GHG emissions. The registry's members include municipalities, private firms, non-profits and other entities.
http://www.climateregistry.org/

The CCAR website contains contact information for recommended providers of technical assistance on GHG mitigation:
http://www.climateregistry.org/SERVICEPROVIDERS/TA/
and third-party certification of GHG emissions inventories:
http://www.climateregistry.org/SERVICEPROVIDERS/Certifiers/
The emission calculation and reporting tool, CARROT, can be found at:
http://www.climateregistry.org/CARROT/

The GHG Protocol Initiative was established in 1998 by the non-profit organization World Resources Institute (http://www.wri.org/). The Initiative develops internationally-accepted accounting and reporting standards for GHG emissions from private firms.
http://www.ghgprotocol.org/

BASELINE, ADDITIONALITY, QUANTIFICATION, MONITORING & VERIFICATION

The "GHG Protocol Project Quantification Standard – Road Test and Review Draft" from the GHG Protocol Initiative is the recommended protocol for project accounting procedures regarding baseline, additionality and quantification.
http://www.ghgprotocol.org/resources_and_documentation/projectmodule.htm

The CCAR provides guidance for forestry projects on baseline, quantification, monitoring and verification.
http://www.climateregistry.org/PROTOCOLS/

The International Performance Measurement and Verification Protocol is a U.S. DOE effort to unify methods for determining energy and water savings from projects. These protocols are being used to guide quantification, monitoring and verification on GHG mitigation projects that improve energy efficiency.
http://www.ipmpv.org

ANCILLARY IMPACTS

The use of a scaled-down version of the Environmental Impact Assessment (EIA) methodology is a suggested approach for assessing ancillary impacts due to GHG mitigation projects. Guidance on EIA methodology can be found in many sources; two are recommended here:

Canter, L. 1996. *Environmental Impact Assessment*. Second edition. McGraw Hill.

California Environmental Quality Act (CEQA) Guidelines, *Appendix G Environmental Checklist Form*. Available at the California Association of Environmental Professionals website: http://www.califaep.org/initstudy.htm

FOREST SEQUESTRATION

The U.S. EPA has a website addressing carbon sequestration in agriculture and forestry which contains information on land-based sequestration issues and outside links to corporations involved in sequestration activities. http://www.epa.gov/sequestration/project_analysis.html

AGRICULTURAL SEQUESTRATION

In April 2004, the USDA completed a comprehensive study of the economics of agricultural sequestration in the US.
http://www.ers.usda.gov/publications/TB1909/

Dr. Rattan Lal, a Professor of Natural Sciences at the Ohio State University, has co-authored two leading textbooks on agricultural sequestration in the US.

Lal, R., Kimble, J.M., Follett, R. F., Cole, C.V. (1999). *The Potential of U.S. Cropland to Sequester Carbon and Mitigate the Greenhouse Effect*. Boca Raton, FL: Lewis Publishers.

Lal, R., Kimble, J.M., Follett, R. F., Cole, C.V. (2000). *The Potential of U.S. Grazing Land to Sequester Carbon and Mitigate the Greenhouse Effect*. Boca Raton, FL: Lewis Publishers.

GEOLOGICAL SEQUESTRATION

The non-partisan think tank, Resources for the Future (RFF), published a report outlining the processes concerning and potential of geological sequestration in the US.
http://www.rff.org/rff/Documents/RFF-DP-02-68.pdf

METHANE CAPTURE AND USE

The U.S. EPA has extensive information resources on this topic. The landfill methane outreach program focuses on opportunities for methane capture and use at existing landfills.
http://www.epa.gov/lmop

The EPA's AgStar program is a valuable source of information about manure management and methane recovery systems at confined animal feeding operations.
http://www.epa.gov/agstar

BIOMASS TO ENERGY

The U.S. DOE Biomass Program initiates and funds numerous biomass to energy projects that are managed (or co-managed) by outside organizations. This research effort provides an opportunity to small municipal utilities for collaborative implementation of biomass to energy GHG mitigation. A list of projects under the Biomass Program is at: http://www.eere.energy.gov/biomass/project_factsheets.html

RENEWABLE ENERGY

The DOE's Energy Efficiency and Renewable Energy (EERE) website includes descriptions of energy efficiency and renewable energy programs, as well as links to current projects and case studies.
http://www.eere.energy.gov/

The Wind and Hydropower Technologies Program is located within the DOE's Energy Efficiency and Renewable Energy program. They have published a brochure that showcases current use of wind energy by municipal utilities.
http://www.nrel.gov/docs/fy03osti/31679.pdf

The Renewable Energy Policy Project produces and facilitates information and research related to renewable energy.
http://www.repp.org/

(DEMAND SIDE) EFFICIENCY IMPROVEMENTS

D&R International is a consulting firm that has worked with California's IOU's and municipal utilities to develop and market energy efficient products and services. http://www.drintl.com/

The European Greenlight Programme (an initiative promoted by the European Commission) uses lighting efficiency programs to reduce polluting emissions; provides guidelines for verify reductions from these projects.
http://www.eu-greenlight.org/

OTHER RESOURCES

The DOE's Office of Fossil Energy and the National Energy Technology Laboratory (NETL) work on research related to fossil fuels and geological sequestration.
http://www.netl.doe.gov/

The US Agency for International Development's (USAID) Global Center for Environment and Office of Energy, Environment and Technology work on international energy supply projects.
http://www.usaid.gov/

Glossary

ADDITIONALITY
A mitigation project has additionality if the GHG mitigation would *not* have taken place in absence of the project. As a result, the project creates a surplus of GHG mitigation benefits *beyond* the business as usual scenario (Chomitz, 2002).

AFFORESTATION
Planting of new forests on lands that have not been recently forested (Pew Center, n.d.).

ANCILLARY IMPACTS
All non-GHG-related effects due specifically to the implementation of a mitigation project (IPCC, 2001c). These effects can be positive (benefits) or harmful (losses), and generally fall under the categories of human and environmental health, and social impacts (Davis et al., 2000).

ANTHROPOGENIC EMISSIONS
Emissions of greenhouse gasses resulting from human activities (Pew Center, n.d.).

BASELINE
See *Emissions Baseline*, *Project Baseline*.

BIODIVERSITY
The variety of organisms found within a specified geographic region (Pew Center, n.d.).

CLEAN DEVELOPMENT MECHANISM
A component of Kyoto Protocol that would allow firms in wealthy countries to claim GHG emission reduction credits for transferring clean technology to developing countries (Spray and McGlothin, 2001).

CLIMATE CHANGE
Changes in long-term trends in the average climate, such as changes in average temperatures (Pew Center, n.d.)

CLIMATE NEUTRAL
A situation of net zero emissions of GHGs to the atmosphere.

DISCOUNTING
A reduction in future costs and benefits to reflect the time value of money and the common preference of consumption now rather than later (Pew Center, n.d.). A slightly different meaning is also used; a reduction in the calculated amount of GHG's mitigated by certain projects to reflect that those GHGs are not kept out of the atmosphere permanently.

EMISSIONS
Release of GHGs and/or their precursors into the atmosphere over a specified area and period of time (UNFCCC).

EMISSIONS BASELINE

The amount of GHGs emitted by an organization (e.g. a utility) in a reference, or baseline, year. Changes in the organization's emissions levels are quantified with respect to the emissions in the baseline year (CA H&S Code, §42801.1(b), 2004). Under the Kyoto Protocol, the reference year is 1990.

EMISSIONS CAP
A limit on the total amount of anthropogenic GHG emissions that can be released into the atmosphere over a certain timeframe. This can be measured as gross emissions or as net emissions (emissions minus gases that are sequestered) (Pew Center, n.d.).

EMISSIONS TRADING
A market mechanism that allows emitters (countries, companies or facilities) to buy emissions from or sell emissions to other emitters. This mechanism is expected to bring down the costs of meeting emission targets by allowing those who can achieve reductions less expensively to sell excess reductions (e.g. reductions in excess of those required under some regulation) to others with higher reductions costs (Pew Center, n.d.).

GLOBAL WARMING
The progressive, gradual rise of the Earth's average surface temperature caused, in part, by increased concentrations of GHGs in the atmosphere (Pew Center, n.d.).

GLOBAL WARMING POTENTIAL (GWP)
An index value for a greenhouse gas that describes its capacity to warm the atmosphere relative to that of CO_2. For example, over the next 100 years, a gram of methane (CH_4) in the atmosphere is currently estimated to be 23 more effective at trapping heat than a gram of CO_2 (Pew Center, n.d.).

GREENHOUSE GAS LIABILITY
The amount of GHG emissions by a business for which it could be responsible under climate change regulations. Due to the current lack of GHG emissions limitations in the U.S., this is a potential liability.

INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (IPCC)
The IPCC was established in 1988 by the World Meteorological Organization and the UN Environment Programme. The IPCC is responsible for providing the scientific and technical foundation for the United Nations Framework Convention on Climate Change (UNFCCC), primarily through the publication of periodic assessment reports (Pew Center, n.d.).

KYOTO PROTOCOL
An international treaty signed in Kyoto, Japan in 1997 that would commit the developed countries to reduce emissions of carbon dioxide and other GHGs to a total of 5.2% below 1990 levels, averaged over the period 2008-2012. The treaty entered into force on February 16, 2005. The United States is not a party to the treaty (Spray and McGlothin, 2001).

LEAKAGE
A situation in which GHG mitigation that is achieved in one location leads to increased GHG emissions elsewhere (Toman, 2001).

PERMANENCE
The length of time that GHGs are removed from, or kept out of, the atmosphere (Murray, 2004).

PROJECT BASELINE
The predicted amount of GHG emissions that would have occurred in the absence of a proposed mitigation project. This baseline serves as a reference level against which the mitigation benefits of a project are measured (UNFCCC, 29 October – 10 November 2001).

RADIATIVE FORCING

Changes in the energy balance of the earth-atmosphere system in response to a change in factors such as GHG emissions, land-use change, or solar radiation. The climate system inherently attempts to balance incoming (e.g., light) and outgoing (e.g., heat) radiation. Positive radiative forcings increase the temperature of the lower atmosphere, which in turn increases temperatures at the Earth's surface. Negative radiative forcings cool the lower atmosphere (Pew Center, n.d.)

REFORESTATION

Planting forests on lands that have recently been logged.

RENEWABLE ENERGY

Energy obtained from sources such as geothermal, wind, photovoltaic, solar, and biomass (Pew Center, n.d.).

SEQUESTRATION

The long-term storage of captured GHGs in a sink other than the atmosphere (IPCC, 2001a).

SINK

Any process, activity or mechanism which removes GHGs, an aerosol or a precursor of a GHG from the atmosphere (UNFCCC)

SOURCE

Any process or activity which releases a GHG, an aerosol or a precursor of a GHG into the atmosphere (UNFCCC).

UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (UNFCCC)

A treaty signed at the 1992 Earth Summit in Rio de Janeiro that calls for the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." The treaty includes a non-binding call for developed countries to return their emissions to 1990 levels by the year 2000. The treaty took effect in March 1994 upon ratification by more than 50 countries (Pew Center, n.d.).

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