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Volume 2 of 3

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Volume I

Part 1 - Electricity Supply Sector

Part 2 - Residential and Commercial Buildings Sector

Part 3 - Industrial Sector

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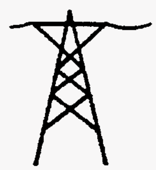
Volume I

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Part 1: Electricity Supply Sector



Part 2: Residential and Commercial Buildings Sector

Part 3: Industrial Sector

Contents of Volume I

This volume, the first of two such volumes, contains sector-specific guidance in support of the General Guidelines for the voluntary reporting of greenhouse gas emissions and carbon sequestration. This voluntary reporting program was authorized by Congress in Section 1605(b) of the Energy Policy Act of 1992.

The General Guidelines, bound separately from this volume, provide the overall rationale for the program, discuss in general how to analyze emissions and emission reduction/carbon sequestration projects, and address programmatic issues such as minimum reporting requirements, time parameters, international projects, confidentiality, and certification. Together, the General Guidelines and the guidance in these supporting documents will provide concepts and approaches needed to prepare the reporting forms.

This first volume contains guidance for the electricity supply sector, the residential and commercial buildings sector, and the industrial sector. The second volume of sector-specific guidance covers the transportation sector, the forestry sector, and the agricultural sector. If you need copies of the General Guidelines or Volume II, contact the United States Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585.

Reporting forms are available at the following address: United States Department of Energy, Energy Information Administration, 1000 Independence Avenue, SW, Washington, DC 20585.

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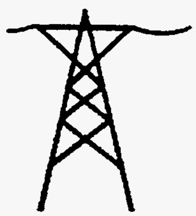
Acronyms

AFV	alternative fueled vehicle
ARB	California Air Resources Board
ARC	Assessment Recommendation Code
ASM	Annual Survey of Manufactures
BDT	Best Demonstrated Technology
bf	board feet
BMP	Best Management Practice
CAA	Clean Air Act
CARE	Cost and Return Evaluator
CE	current efficiency
CEM	continuous emissions monitoring
CFC	chlorofluorocarbon
CFM	cubic feet per minute
CM	Census of Manufactures
CRP	Conservation Reserve Program
CVP	Conservation Verification Protocols
DOE	Department of Energy
DOT	Department of Transportation
DSM	demand-side management
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPIC	Erosion Productivity Index Calculator
EPRI	Electric Power Research Institute
ESCO	energy service company
FFV	flexible-fueled vehicle
Gg	gigagram
GJ	gigajoule
HAP	hazardous air pollutant
HCFC	hydrochlorofluorocarbon
HFC	hydrofluorocarbon
HVF	heating value factor
I/M	inspection and maintenance
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRP	integrated resource planning
kW	kilowatt
kWh	kilowatt/hour
LEPA	low energy precision application
MCFM	thousand cubic feet per minute
MECS	Manufacturing Energy Consumption Survey
MOU	Memorandum Of Understanding
MPO	metropolitan planning organization
MSHA	Mining Safety and Health Administration
MSW	municipal solid waste
MT	metric ton
MWh	megawatt hour
N	nitrogen
NMOC	nonmethane organic compound
OPS	Office of Pipeline Safety
VA	Organic Vapor Analyzer
PEC	portable evacuation compressors
PFC	perfluorocarbon
PJ	petajoule
ROG	reactive organic gas
RTECS	Residential Transportation Energy Consumption Survey
SCS	Soil Conservation Service
SI	Standard International
SOC	soil organic carbon
SPUR	Simulation of Production and Utilization of Rangeland
ST	short ton
SWCD	soil and water conservation district
T&D	transmission and distribution
USDA	U.S. Department of Agriculture
VOC	volatile organic compound

Electricity Supply Sector

Part 1 of 6 Supporting Documents



Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Electricity Supply Sector

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1.0 Electricity Supply Sector

This document supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act (EPAct) of 1992. The General Guidelines provide the rationale for the voluntary reporting program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this supporting document, you should read the General Guidelines. Then read this document, which relates the general guidance to the issues, methods, and data specific to the electricity supply sector. Other supporting documents address the residential and commercial buildings sector, the industrial sector, the transportation sector, the forestry sector, and the agricultural sector.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon sequestration projects. When you understand the approaches taken by the voluntary reporting program, you will have the background needed to complete the reporting forms.

The General Guidelines and supporting documents address four major greenhouse gases: carbon dioxide, methane, nitrous oxide, and halogenated substances. Although other radiatively enhancing gases are not generally discussed, you will be able to report nitrogen oxides (NO_x), nonmethane volatile organic compounds (NMVOCs), and carbon monoxide (CO) after the second reporting cycle (that is, after 1996).

The Department of Energy (DOE) has designed this voluntary reporting program to be flexible and easy to use. For example, you are encouraged to use the same fuel consumption or energy savings data that you may already have compiled for existing programs or for your own internal tracking. In addition, you may use the default emissions factors and stipulated factors that this document provides for some types of projects to convert your existing data directly into estimated emissions reductions. The intent of the default emissions and stipulated factors is to simplify the reporting process, not to discourage you from developing your own emissions estimates.

Whether you report for your whole organization, only for one project, or at some level in between, you will find guidance and overall approaches that will help you in analyzing your projects and developing your reports. If you need reporting forms, contact the Energy Information Administration (EIA) of DOE, 1000 Independence Avenue, SW, Washington, DC 20585.

1.1 Electricity Supply: Overview

The electricity supply sector consists of generation, transmission, and distribution subsystems.

- The generation system consists of units powered by coal, nuclear energy, water, oil, gas, or renewable sources, together with generation substations that connect the generators to transmission lines.

- The transmission system carries bulk power from generation substations to transmission substations located along lines in the system. The subtransmission system routes power to distribution substations, which are the points of power delivery to the distribution network.

- The distribution system delivers power supplied by the transmission and subtransmission network through a system of primary feeders, laterals, and secondary feeders to the utility's customers. The combined transmission and distribution (T&D) system connects the generation facilities with all end-use loads served by the utility.

Emissions-reducing projects in this sector can reduce primary inputs of fuels to the system, especially in the generation system; increase the efficiency of energy used or delivered; decrease energy losses in the T&D system; and decrease demand for electricity. Possible projects range from those that have direct, easily measurable emissions effects (such as fuel switching) to those that have indirect, difficult-to-estimate effects (such as efficiency improvements in T&D equipment).

1.1.1 Reporting Entities

Entities in this sector may fall into one of several categories: electric utilities or their subsidiaries, nonutility power producers, suppliers to the electric power industry, end users, or utility research/information organizations. An electric utility could be one of the following: investor-owned, rural electric cooperative, municipal utility or agency, government power authority, or power pool. Nonutility power producers include qualifying generators, qualifying small power producers, and other nonutility generators, including independent power producers (IPPs). Typical suppliers to the electric power industry include manufacturers of T&D equipment, other manufacturers or service suppliers, manufacturer's representatives, distributors, consultants, marketing entities, or contractors/constructors. End users are in the industrial, institutional, commercial, or residential sectors. Research organizations may include such entities as the Electric Power Research Institute (EPRI).

If your company has multiple subsidiaries, you may choose to aggregate some or all of your projects in a single report or to have the subsidiaries report separately. Your decision to report on an entity-wide basis or separately must be based on the types of emissions reduction activities, keeping in mind that you must report the significant effects of a project. (See the General Guidelines, "What Effects Did the Project Have?")

1.1.2 Sector-Specific Issues

Generally speaking, issues in the electricity supply sector revolve around selecting, analyzing, and reporting information that is already available or easily derived. The interconnectedness of the parts of the grid vis a vis the move toward greater competition also raise issues of multiple reporting and confidentiality.

As a part of the electricity supply sector, you likely collect and report many types of data, including information on fuel use, system efficiency, and emissions to the air, water, and soil. For example, you may hold tradable permits under the Acid Rain Program. You may also already participate in programs that address climate change issues. You may be working with DOE on Climate Challenge, for which this voluntary reporting program is the principal reporting mechanism. You may be able to use the information or estimation methods developed for these other programs as a basis for your EPAct Section 1605(b) reports.

The integrated resource planning (IRP) process may provide a rich source of data you can use to develop reports under this voluntary reporting program. EPAct amends the Public Utility Regulatory Policies Act to require IRP, and public utility commissions (PUCs) in many jurisdictions are requiring utilities to incorporate IRP results into their reporting systems. The objective of IRP is to minimize the total cost of meeting demand for energy services. EPAct defines the IRP process as

> a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, to provide adequate and reliable service to its electric customers at the lowest system cost (EPAct Section 111[d]).

The emphases on conservation, efficiency, alternative technologies, and renewable resources should both lead to adoption of emissions-reducing activities and provide data for reportable projects under the EPAct 1605(b) program. However, the focus of IRP is on least cost, not on emissions reductions, so you will likely need to perform some additional estimating in order to report under this program.

The electricity supply sector is also characterized by a wealth of methodologies that you can use to develop reports under this voluntary reporting program. You probably perform calculations with different estimation tools for a wide diversity of purposes. Some available methodologies, such as those set forth by the Intergovernmental Panel on Climate Change (IPCC 1991) and the Environmental Protection Agency (EPA 1990), were designed specifically to measure greenhouse gases or other emissions of environmental concern (for example, acid rain precursors). Other methods were designed for economic purposes and thus focus on fuel/energy use and efficiency. EIA, power marketing administrations, EPRI, and others collect data that, together with additional data such as default emissions factors, may be used to estimate greenhouse gas emissions.

To develop reports under this program, you may also use the stipulated factors by technology provided by this document for greenhouse gas emissions, primarily for non-carbon dioxide gases. (Carbon dioxide emissions rates depend almost entirely on the fuel use characteristics, not technology use.)

You may have developed estimating methods specific to your organization, perhaps adapted from standard methods but using measured/monitored data. On the other hand, you may use standard methods to be responsive to existing reporting requirements to your public utility commission and others. The examples in this supporting document and Case 3 in the General Guidelines will give you an idea of the range of options open to you. Under this voluntary reporting program, you may choose the methods that will help you build a credible report. In your report, you must identify or describe the methods you used to estimate your emissions and emissions reductions (see the General Guidelines, "What Are the Minimum Reporting Requirements?"). You may further wish to keep a complete set of data and calculations to back up your reports under this program.

When more than one party is involved in generating emissions or achieving emissions reductions, all or several may decide to report jointly, or each may report separately. (See the General Guidelines, "What If Two or More Organizations Wish to Report the Same Project?") For example, if you sell or purchase power, any or all sellers and purchasers may report under this voluntary program. A joint report would have the advantage of comprehensiveness, with full data provided for a complete picture of a utility's emissions and emissions reductions. If you do not report jointly, each seller and purchaser should identify the other as a possible reporter.

You may also wish to report jointly when you have been engaged with others on emissions-producing and emissions reduction activities. A special instance of this is the generation and transmission cooperatives, where estimation of emissions and projects can probably be most accurately and easily accomplished for the entire operation.

You may choose to report through a third party that could aggregate emissions reductions for a group of entities with similar backgrounds and methods for reporting. The third party could provide an additional layer of confidentiality, and your contributions would not have to be individually identified in the report. Examples of such third-party entities include government power authorities, regional transmission groups, regional reliability councils, trade associations, or engineering/energy service companies. A third party might also provide technical assistance in carrying out emissions reduction projects and reporting. For example, the Western Area, Southwestern, and Southeastern Power Administrations have jointly developed a set of integrated resource planning (IRP) tools called the *Resource Planning Guide* (WAPA et al. 1993), designed to help small- and mid-sized utilities analyze supply and demand-side management (DSM) alternatives.

When another party is involved in identifying, implementing, or paying for the emissions reduction project, you should identify that party to track possible multiple reporting. For example, when a utility replaces an existing fossil-fuel-fired plant with a gas turbine combined cycle system, the manufacturer of the turbine system should be identified. Similarly, if you submit data on emissions reductions to one or more trade associations, you should identify all those parties.

1.1.3 Key Concepts for Electricity Sector Analysis

For the electricity supply sector, your analysis should take into account two important distinctions: between direct and indirect emissions and between fuel-based and technology-based emissions. These will influence how you estimate emissions and perform project analyses (see Sections 1.2, 1.5, and 1.6).

- ***Direct vs. Indirect Emissions:*** Some activities in the electricity supply sector produce emissions directly, that is, from combusting fossil fuel in the electricity generation process. Other operations determine how electricity is transmitted, distributed, and used. These activities do not themselves produce emissions but indirectly affect emissions levels from the generating activities by affecting how much electricity must be produced. If you are *not* reporting total emissions for your whole organization, you will need to approach direct and indirect activities differently, especially when you estimate emissions (see Section 1.2).

  Three general approaches can be taken to estimate reductions in greenhouse gas emissions in the electricity supply sector:

- For *direct emissions* (from the generation subsystem), measure or calculate greenhouse gases with and without emission-reducing activities, and then calculate the net reduction in greenhouse gas emissions.

- For *direct emissions* from activities that involve *a combination of fuels*, calculate the change in greenhouse gas emissions for each fuel and then, for each gas, sum across the fuels to obtain the net reduction in emissions of each gas.

- For *indirect emissions*, calculate the energy savings from the energy activity and multiply the savings by a greenhouse gas emissions factor (see Section 1.7).

- ***Fuel-Based vs. Technology-Based Emissions:*** In the electricity supply sector, most carbon dioxide emissions levels are directly related to the type and quantity of fossil fuel combusted. Therefore, unless you directly monitor your emissions, you will likely begin with data on types and amounts of fuel consumed by your operations, then derive the amount of carbon contained in the fuels, and finally convert the carbon figure to an amount of carbon dioxide (see Appendix D).

  Emissions of greenhouse gases, however, can be estimated by data associated with the combustion technologies. Table 1.1 provides stipulated factors that you can use in generating reports under this voluntary reporting program if you do not directly monitor your emissions.

1.2 Estimating and Reporting Greenhouse Gas Emissions

The General Guidelines ("What is Involved in Reporting Emissions?") explain that reporting information on greenhouse gas emissions for the baseline period of 1987 through 1990 and for subsequent calendar years on an annual basis is considered an important element of this voluntary reporting program. If you are able to report emissions for your entire organization, you should consider providing a comprehensive accounting of such emissions so that your audience can gain a clear understanding of your overall activities.

1.2.1 Direct Emissions

Direct emissions (from fuels used at your generation sites) may be monitored or estimated. Monitoring emissions is discussed in Section 1.5.1, including continuous emissions monitoring (CEM) and stack approaches to monitoring. This section discusses a procedure for estimating greenhouse gas emissions from generation subsystem sources based on methodologies recommended by the IPCC (1991) and EPA (1990). You may use these methodologies to calculate emissions reductions in project analysis (see Section 1.7). Carbon dioxide is addressed separately from other energy-related greenhouse gases because the methods are fundamentally different. Carbon dioxide emissions depend primarily on fuel properties, while non-carbon dioxide greenhouse gases are primarily related to technology and combustion conditions.

Direct carbon dioxide emissions

Carbon dioxide emissions occur primarily from combustion of fossil fuels. Most carbon in fuel is emitted as carbon dioxide during the combustion process. Therefore, the method to estimate greenhouse gas emissions begins with determining amounts of fuels and amounts of carbon in those fuels. When you have estimated the total carbon, you can easily estimate the carbon dioxide that results from combusting the carbon. The following method is modified from the IPCC (1991) standard approach.

To estimate direct carbon dioxide emissions, follow the four steps below. Example 1.1 illustrates the method used in a hypothetical situation:

1. Identify the type of fuel consumed and energy consumption by fuel type. Energy consumption data by fuel type may be derived from data you supply to EIA (see the EIA report listing in Appendix 1.A and, for example, Form EIA-767) or to EPA under its Acid Rain Program. If you only know fuel quantity, you can calculate the energy supplied by using the heating value factors (HVFs) in IPCC (1991). (When these HVFs and other data are updated by the IPCC, you should use the most current numbers.)

2. Determine the carbon emissions coefficients of the fuels identified and total carbon potentially released from use of the fuels. Default values for greenhouse gas emissions per unit of energy

for most common fossil fuels are provided in Appendix B, Emissions Factors. If you do not know the carbon content of a fossil fuel, but can identify the type, you should use an average emission/unit energy value for that fuel. For coal, carbon emissions per ton vary considerably, depending on the coal's composition. Although variability of carbon emissions on a mass basis can be considerable, carbon emissions per unit of energy (for example, per gigajoule) vary much less.

3. Using the values from Steps 1 and 2, estimate carbon oxidized from energy uses. (See Table C.2 in Appendix C for U.S. data.) For natural gas, less than 1 percent of the carbon in natural gas is unoxidized during combustion and remains as soot in the burner, in the stack or in the environment. For oil, 1.5 percent passes through the burners and is deposited in the environment without being oxidized. For coal, 1 percent of carbon supplied to furnaces is discharged unoxidized, primarily in the ash. In general, you may assume that 99 percent of carbon is oxidized during combustion.

4. Convert the net carbon oxidized during combustion to total carbon dioxide emissions. The conversion factor for translating carbon emissions into carbon dioxide emissions is 3.67, as explained in Appendix D.

This four-step method is shown by the following equation, using standard international units:

$$E_a = FC_a \bullet CECo_a \bullet 0.99 \bullet 3.67$$

where E_a = carbon dioxide emissions for fuel a (in gigagrams)
FC_a = energy consumption of fuel a (in petajoules)
$CECo_a$ = carbon emissions coefficient for fuel a (in kilograms of carbon/gigajoule)
0.99 = oxidation factor
3.67 = conversion factor (carbon to carbon dioxide) (See Appendix D).

The same equation may be written using English units:

$$E_a = FC_a \bullet CECo_a$$

where E_a = carbon dioxide emissions for fuel a (in pounds)
FC_a = energy consumption of fuel a (in million Btu)
$CECo_a$ = carbon dioxide emissions factor for fuel a (in pounds of carbon dioxide/million Btu) (See Appendix C and DOE/EIA 1992).

Note on using Standard International (SI) Units

Because greenhouse gas emissions raise global issues, international organizations such as the IPCC have developed estimating methods using standard international (SI) units such as petajoules and gigagrams. These metric units are presented in the guidelines as features of these internationally used methods. However, you may report in English units such as pounds and short tons. The EIA forms for this voluntary reporting program allow you to specify the units you use.

Metric SI units used in these supporting documents are listed in Appendix A to this volume, along with conversion factors to English units. Of particular interest for methods used in electricity supply are the following:

petajoules (PJ)	=	10^{15} joules	= 947.8×10^9 Btu
gigajoules (GJ)	=	10^9 joules	= 947.8×10^3 Btu
gigagram (Gg)	=	10^3 metric tons	= 1.1025358×10^3 short tons

You may be more familiar with using British units. Therefore, the initial example, 1.1, in which SI units appear, is repeated using English units.

Example 1.1 - Calculation of Direct Carbon Dioxide Emissions (Standard International Units)

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Northern Electric, at its Pine River power plant, consumed 1 million metric tons (MT) of sub-bituminous coal per year. To calculate total carbon dioxide emissions in that year, the utility used the modified IPCC methodology reflected in the equation discussed in Section 1.2.1 of this document:

$E_a = FC_a \bullet CECo_a \bullet 0.99 \bullet 3.67$

Step 1. Northern converted metric tons to energy consumption in petajoules. Using the IPCC (1991) value of 19.4 GJ/metric ton for sub-bituminous coal (see Appendix 1.C), Northern calculated its total annual coal energy consumption.

FC = Annual coal energy consumption = 10^6 MT coal • 19.4 GJ/metric ton • 10^{-6} PJ/GJ = 19.4 PJ

Step 2. The utility determined the carbon emissions coefficient from Table C.1:

CECo = Emissions coefficient for sub-bituminous coal = 26.1 kg C/GJ

Step 3. Northern was then ready to calculate total carbon oxidized, using the values from Steps 1 and 2:

Total Carbon oxidized = 19.4 PJ • 26.1 kg C/GJ • 10^6 Gg/kg • 10^{-6} PJ/GJ • 0.99 = 501.3 Gg carbon

Step 4. Finally, Northern converted the net carbon oxidized to carbon dioxide emissions, using the conversion factor described in Appendix D:

E = Total CO_2 = 3.67 Gg CO_2/Gg C • 501.3 Gg carbon = 1,839.7 Gg CO_2

The Pine River power plant consumed 1 million tons of coal and reports emissions of 1,839 Gg, or approximately 1.8 million metric tons of carbon dioxide annually (1 Gg = 10^3 metric tons).

Example 1.1 - Calculation of Direct Carbon Dioxide Emissions (English Units)

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Northern Electric, at its Pine River power plant (located in Montana), consumed 1 million short tons (ST) of sub-bituminous coal per year. To calculate total carbon dioxide emissions in that year, the utility used the modified IPCC methodology reflected in the equation discussed in Section 1.2.1 of this document:

$E_a = FC_a \bullet CECo_a$

Step 1. First, Northern converted short tons to energy consumption in million Btu. Using its own value of 18 million Btu/short ton for sub-bituminous coal, Northern calculated its total annual coal energy consumption.

FC = Annual coal energy consumption = 10^6 ST coal x 18 million Btu/short ton = 18×10^6 million Btu

Step 2. The utility determined the carbon dioxide emissions factor from Table C.2 of DOE/EIA (1992):

CECo = Emissions factor for sub-bituminous Montana coal = 213.4 lb CO_2/million Btu

Step 3. Northern was then ready to calculate total carbon dioxide emissions, using the values from Steps 1 and 2:

Total CO_2 = 18×10^6 million Btu • 213.4 lb CO_2/million Btu = 3,841.2 million lb

The Pine River power plant consumed 1 million short tons of coal and reports emissions of 3,841 million pounds, or approximately 1.9 million short tons of carbon dioxide annually (1 short ton = 2,000 pounds).

In the example above, Northern Electric estimated the major component of its emissions at one plant. A more complete accounting would include Northern's other facilities and other emissions-producing activities. However, you may not have access to all the information you need to estimate your aggregate emissions. If you have partial information that includes most emissions, you should note in your report what activities are and are not included. For example, an IPP and a utility may report energy consumption emissions separately, noting other activities for which they are not directly responsible.

When you report historic emissions, you should note the activities that are excluded because you lack information. If you report emissions for several different years, you should report reasons for changes, including changes in the volume of business, internal efficiency, and types of services delivered; the amount of outsourcing; or other factors that could account for differences from year to year.

Direct non-carbon dioxide emissions

Carbon dioxide is not the only greenhouse gas emitted by fuel combustion. Other gases such as methane and nitrous oxide are also released. You may wish to report data on these other gases as well as carbon dioxide. This section presents a modified IPCC method for estimating emissions and illustrates that method in Example 1.2.

Emissions of non-carbon dioxide greenhouse gases depend on fuel, technology type, and the pollution control technologies. Emissions will also vary more specifically with the size and vintage of the combustion technology, its maintenance, and its operation. When you have data about your fuel consumption for each technology type and wish to estimate the contribution of each gas to that total, you may use the approach outlined in this section. Alternatively, data reported to EIA or EPA's Acid Rain Program can be used to estimate total emissions for each greenhouse gas type of interest.

Based on the modified IPCC methodology, the main steps in determining the non-carbon dioxide emissions can be summarized as follows:

1. Determine your energy input data for each fuel/technology type, using data reported to EIA as appropriate. Basic fuel categories include oil, coal, and other solids and gases.

2. Compile emissions factor data for each fuel/technology combination you use in electricity generation. You may use the representative emissions factors by main technology and fuel types from Table 1.1. These factors represent the average performance of a population of similar technologies. You may also use the Environmental Characterization Data prepared by the National Renewable Energy Laboratory (NREL 1993) to estimate emissions for your technologies. If control technologies are in place, you need to consider their performance.

3. Develop estimates of each greenhouse gas, based on the energy inputs to the various fuel/technology inputs, technology by technology.

4. For each gas, sum across the individual fuel/technology combinations to arrive at the entity-wide total for each greenhouse gas.

Table 1.1. Representative Emissions Factors for Non-Carbon Dioxide Greenhouse Gases

Fuel/Technology Type	Emissions Factors (expressed in grams per gigajoule g/GJ, of energy input[a] and lb/MWh)			
	CH_4 lb/MWh	CH_4 g/GJ	N_2O lb/MWh	N_2O g/GJ
Natural Gas - Boilers	N/A	0.1	N/A	N/A
Gas Turbine Combined Cycle	.015	6.1	.063	N/A
Gas Turbine Simple Cycle	N/A	5.9	.240	N/A
Residual Oil Boilers	N/A	0.7	N/A	N/A
Distillate Oil Boilers	N/A	0.03	.276	N/A
MSW - Mass Feed[b]	.02	N/A	.55	N/A
Coal - Spreader Stoker	N/A	0.7	N/A	0.8
Coal - Fluidized Bed Combined Cycle	N/A	0.6	N/A	N/A
Coal - Fluidized Bed	N/A	0.6	.325	N/A
Coal - Pulverized Coal	N/A	0.6	N/A	0.8
Coal -Tangentially Fired	N/A	0.6	N/A	0.8
Coal - Pulverized Coal Wall Fired	N/A	0.6	N/A	0.8
Wood - Fired Boilers[b]	N/A	18	.55	N/A

(a) Values were originally based on "gross" (or higher) heating value; they were converted to "net" (or lower) heating value by assuming that net heating values were 5 percent lower than gross heating values for coal and oil, and 10 percent lower for natural gas. These percentage adjustments are the assumption from the Organization for Economic Cooperation and Development and the International Energy Agency (cited in IPCC 1991) on how to convert from gross to net heating values as discussed in the IPCC 1991.

(b) Emissions factors were adjusted to lower heating value, assuming a 5 percent difference in energy content between lower heating value and higher heating value.

Source: IPCC 1991 (for g/GJ values); NREL 1993 (for lb/MWh values). N/A = not available

This four-step method may be expressed in the following equation:

$$E_j = \sum_{\text{all } k,l} \left(EF_{jkl} \bullet A_{kl}\right)$$

where E_j = emissions of gas j, in grams
EF_{jkl} = emissions factor (g/GJ), for gas j, fuel type k, technology l, given in Table 1.1
A_{kl} = energy input (GJ) of fuel type k to technology l.

Although carbon dioxide emissions are not technology dependent, they can also be estimated by technology using this "bottom-up" approach, from the data developed to estimate non-carbon dioxide emissions. Specifically, since the fuel type is known, the carbon emission coefficients, by fuel type, provided in Appendix B to this volume, Emissions Factors, can be applied to the total amount of input energy for each fuel/technology type to determine total carbon consumed for that category. To determine the total carbon dioxide emissions, you would sum across all technology/fuel type combinations and then follow steps 3 and 4, as discussed in the earlier section on "Direct carbon dioxide emissions" and illustrated in Example 1.1.

Example 1.2 illustrates the use of this method to calculate non-carbon dioxide emissions (methane) and carbon dioxide emissions for a hypothetical utility.

Example 1.2 - Calculation of Direct Methane Emissions

Notes: (1) This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(2) The fuel type and technology type were selected for illustrative purposes only and may not reflect a realistic situation at a utility.

Rogers Utility (RU) decided to report methane emissions at its Century power plant, in addition to reporting carbon dioxide emissions. RU had one pulverized coal boiler, one fluidized-bed combustion coal boiler, one residual oil boiler, and one combined cycle gas turbine at the Century plant.

The table below illustrates how RU used the following equation to estimate its methane emissions using only data from its records or retrieved from Table 1.1 of this document.

$$E_j = \sum_{\text{all } k,l} \left(EF_{jkl} \bullet A_{kl}\right)$$

Fuel Type	Technology Type	Monthly Fuel Consumption[a]	Conversion Factors[b]	A_{kl} Monthly Energy Input (GJ)	EF_{jkl}, Methane Emissions Conversion Factors (g/GJ)[c]	E_j, Methane Emission (g)
Coal	Pulverized-coal boiler	100,000 MT	1 MT coal = $24\text{x}10^6$ Btu = 25 GJ	$2.5\text{x}10^6$	0.6	$1.52\text{x}10^6$
Coal	Fluidized-bed boiler	100,000 MT	1 MT coal = $24\text{x}10^6$ Btu = 25 GJ	$2.5\text{x}10^6$	0.6	$1.52\text{x}10^6$
Oil	Residual oil boiler	3,000 bbl	1 bbl oil = $5.8\text{x}10^6$ Btu = 6.12 GJ	$18.36\text{x}10^3$	0.7	$12.85\text{x}10^3$
Natural gas	Combined-cycle gas turbine	2,048,000 Mcf	1 Mcf gas = $1.030\text{x}10^6$ Btu = 1.09 GJ	$2.23\text{x}10^6$	6.1	$13.62\text{x}10^6$
Total methane emissions per month						**$16.67\text{x}10^6$**

MT = metric tons; cf = cubic feet; Mcf = one thousand cubic feet = 10^3 cf; bbl = barrels

(a) Amounts given for illustrative purpose.
(b) Source: DOE 1991.
(c) Source: Table 1.1 of this document.

The Century plant emitted 16.67 metric tons of methane per month, or 200.04 metric tons of methane annually. RU wanted to also determine carbon dioxide emissions using this "bottom-up" approach. The utility used the same data developed to estimate non-carbon dioxide emissions, combined with the carbon emissions conversion factors for each fuel type, as given in Appendix 1.C.

Example 1.2 - (cont'd)						
Fuel Type	**Technology Type**	**Monthly Fuel Consumption[a]**	**Conversion Factors[b]**	**Monthly Energy Consumption (PJ)**	**Carbon Emissions Conversion Factors[c] (kg C/GJ)**	**Monthly Carbon Emissions (Gg)**
Coal	Pulverized-coal boiler	100,000 MT	1 MT coal = $24x10^6$ Btu = 25 GJ	2.5	25.8	64.5
Coal	Fluidized-bed boiler	100,000 MT	1 MT coal = $24x10^6$ Btu = 25 GJ	2.5	25.8	64.5
Oil	Residual oil boiler	3,000 bbl	1 bbl oil = $5.8x10^6$ Btu = 6.12 GJ	0.018	20	0.37
Natural gas	Combined-cycle gas turbine	2,048,000 Mcf	1 Mcf gas = $1.030x10^6$ Btu = 1.09 GJ	2.23	15.3	34.12
Total carbon emissions per month						**163.49**

MT = metric tons; cf = cubic feet; Mcf = one thousand cubic feet = 10^3cf; bbl = barrels.

(a) Amounts given for illustrative purpose.
(b) Source: DOE 1991.
(c) Source: Table 1.1 of this document.

RU adjusted this factor to reflect an assumed 99 percent combustion efficiency and converted to annual carbon dioxide emissions.

$$\text{Total annual } CO_2 \text{ emissions} = 163.49 \text{ Gg C/month} \bullet 0.99 \bullet 3.67 \text{ Gg } CO_2\text{/Gg C} \bullet 12 \text{ months/yr}$$
$$= 7.128x10^3 \text{ Gg } CO_2\text{/yr.}$$

Note that both of these calculations for RU's Century plant reflect an assumption that the monthly fuel consumption figures represent an average of all months.

1.2.2 Indirect Emissions

Reporters may be responsible not only for emissions that occur at their own facilities, but also for emissions occurring at other sites. For example, an electricity consumer is indirectly responsible for some portion of the emissions that occur at the electricity generation site. Similarly, an electric utility that purchases power from outside sources contributes indirectly to the emissions of the generator.

If you are reporting emissions in this voluntary reporting program, you may also want to report emissions associated with purchased electricity. If so, you must distinguish between direct and indirect emissions, and you should identify the source of the indirect emissions and how you estimated the quantity of emissions. You may also want to discuss what you are reporting with the generator/seller of the power to identify or avoid multiple reporting of the same emissions.

1.3 Analyzing Emissions Reduction Projects

Section 1.2 discussed methods for estimating emissions; this section and the following sections provide guidance for analyzing projects you have undertaken to reduce those emissions so that you may report reductions. This section provides an overview and rationale for the process, relating the General Guidelines to the electricity supply sector. The following sections discuss specific emissions-reducing measures and methods for estimating the reductions achieved.

Figure 1.1 presents a simplified view of the project analysis process in the electricity supply sector. This process is discussed in the General Guidelines; this and the following sections augment the general guidance with considerations specific to electricity supply.

Define the project. In the project definition step, you determine whether to report emissions levels for your whole organization (entity-level reporting) or some part of it. This decision may be based, in part, on what data you have, what primary effects are associated with the project (for example, will effects show up at the overall organization level?), and who the audience for your report will be (for example, will interested environmental groups find a partial report credible?).

The analysis of emissions reductions projects in the electricity supply sector consists of the basic steps that are discussed in the General Guidelines under the heading "How Should I Analyze Projects I Wish to Report?":

Establish a reference case to use as a basis for comparison with the project. You need to determine your reference case in conjunction with defining your project, since you must establish a basis for comparison. If you wish to compare overall emissions from the project year with those of an earlier year, you may choose a basic reference case. If, however, your purpose is instead to highlight the effects of a specific emissions reductions project for which no historical comparison exists, you may choose a modified reference case.

Identify effects of the project. If you identify significant effects outside your current project definition, you may choose to redefine your project. In any case, you should identify all such effects you can and, if they are large, quantify them to the extent possible.

Estimate emissions for the reference case and the project. If you have monitored data on your total emissions and are reporting at the entity level, you are ready to report after identifying any external effects. Otherwise, your choice of an estimation method may depend on whether emissions are direct or indirect. Direct emissions may be estimated from fuel consumption data and from stipulated factors associated with technologies used to generate electricity. Indirect emissions are estimated from energy savings data (for example, reducing losses in the transmission system) that are then traced back to the generation system to determine the associated emissions reductions.

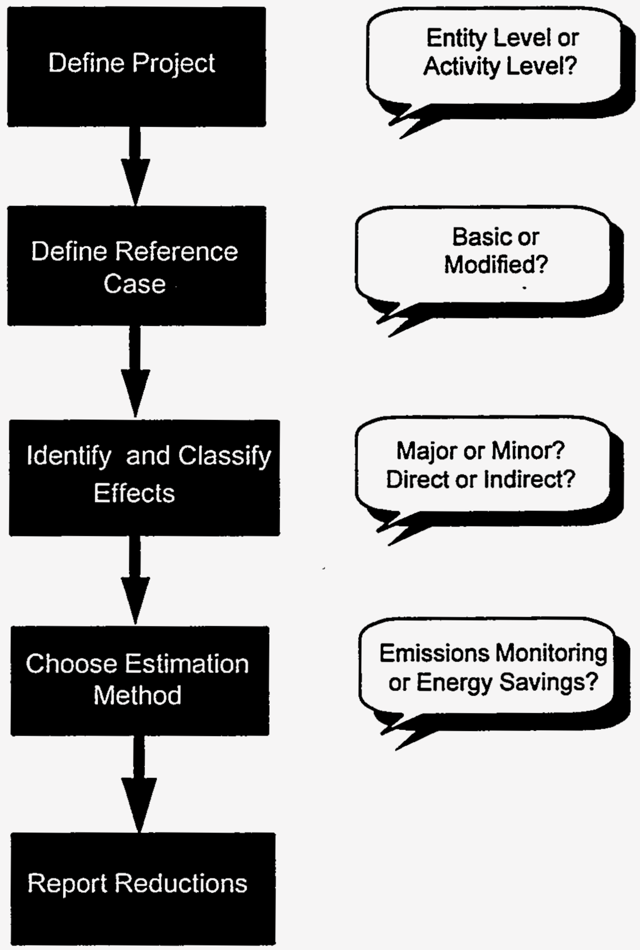

Figure 1.1. Project analysis in the electricity supply sector includes choosing estimation methods based on whether the project is at the entity or activity level and whether emissions effects are direct or indirect. (See Section 1.4.)

Project analysis can be simple or complex, depending upon a number of factors involved in each step. This section discusses the major methodologies used to calculate emissions reductions, but you have the flexibility to choose how to define your project and reference cases and how to estimate emissions reductions.

1.3.1 Establish a Reference Case

The first step after defining a project is identifying and describing a reference case. Emissions reductions are defined as the difference between actual emissions and what emissions would have been had the reported project not been undertaken. The reference case is the expression of what emissions would have been without the project.

You may define a reference case in two ways: a *basic* reference case and a *modified* reference case. A basic reference case is defined as the historic level of emissions; a modified reference case is adjusted to account for your expectation that, during the project year, emissions without the project would have been different from historic levels. Examples 1.3 and 1.4 illustrate situations in which a modified reference case would be appropriate.

Example 1.3 - A Modified Reference Case - Growth and Decline in Demand

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A utility, Ptomkin Standard Electric (PSE), experienced an average growth in electricity demand of 1.3 percent per year. PSE could have met the growth in demand in two ways. One was to add generating plants (supply side resources); the other was to increase the efficiency of its T&D system and reduce demand (under a demand-side management program). Supply-side resources could have been built either by the utility itself or by a nonutility—an independent power producer.

To find the best mix of these resources, PSE engaged in the IRP process required by its public utility commission. IRP, an emerging planning standard for utilities, seeks full integration of forecasting, consideration of DSM, supply planning, T&D resources, rate and financial planning, and strategic management activities.

As a result of the IRP process, PSE was committed to a program to reduce a considerable amount (50 to 60 percent) of the growth in electricity demand in the next 10 years by promoting conservation of electricity. PSE could have met this commitment by a combination of DSM options (rebates to customers for more efficient lighting, motors, and air conditioning) and supply-side options (independent power production in the short term and repowering of some existing plants later).

Since PSE's demand *was and would be changing* from year to year, PSE used a modified reference case to report its projects. Furthermore, PSE's project analysis included the independent power production. To establish its modified reference case, PSE had data generated for the IRP report to its public utility commission which it verified against measurement data reported under the EPA's Acid Rain Program.

Once PSE established its modified reference case, the process for calculating and reporting emissions reductions for PSE followed the same steps as described in Sections 1.5, 1.6, and 1.7.

Example 1.4 - A Modified Reference Case - New Generating Capacity

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A new IPP, Cogen, Inc., used combustion turbine technology to produce power as a cogenerator (that is, produce electricity while making use of the waste heat) for Ptomkin Standard Electric (PSE). Because Cogen had not existed the previous year, it could not use a basic reference case if it wished to report under this program. Cogen had to use a modified reference case, based on external data obtained from PSE, to determine what emissions would have been (but for the project) in the year in which the project's effects are being measured. Cogen needed to access PSE's data generated for the IRP report and measurement data reported to EPA's Acid Rain Program.

1.3.2 Identify Effects of the Project

Some projects have limited, well-defined effects. For example, improving the system efficiency of a boiler has beneficial effects but virtually no effects beyond the operation of the boiler itself. Other activities, such as fuel switching from coal to natural gas, may have the effect of reducing emissions related to serving baseload demand, but may also induce a change in the dispatching patterns. The switch to natural gas may also lead to higher methane emissions or lower transportation-related greenhouse gas emissions. In some instances, especially where two or more projects are undertaken simultaneously, you may not be able to distinguish the emissions effects of any given activity from the effects of other activities.

This raises two associated issues for project analysis. First, you must decide whether to concentrate your analysis narrowly on activity-level effects (see Example 1.5), broadly on entity-level effects, or even more broadly to include effects outside your organization (see Example 1.6). The underlying assumption in entity-level analysis is that any detected changes in entity-level emissions can be attributed to the project(s). The second issue is that, regardless of whether you focus your analysis narrowly or broadly, you should identify effects that are not accounted for within the scope of your analysis.

In theory, for a given project, an analysis narrowly focused at the activity level would produce the same estimate of emissions reductions as an analysis focused at the entity level if (1) the analysis fully accounted for and quantified all effects and (2) all changes to your organization's emissions can be attributed to the project. However, these two conditions are seldom met. For example, a utility might replace all distribution transformers on a feeder with energy efficient transformers, but find that economic growth in the region increased power demand and the resultant emissions did not decrease as much as planned. Therefore, you should carefully consider the focus of your analysis. If you are considering a narrowly focused analysis, but are finding that the project has significant effects elsewhere in your operations, you may more easily carry out the analysis through an entity-level estimation. At the same time you may find that estimating your project's effects is difficult to evaluate through entity-level measures because of other changes in your operations that obscure those effects.

Note that in one case the information needed for emissions reporting (see Section 1.3) is identical to the data needed for project evaluation. This occurs when (1) emissions reporting is at the entity level, (2) a basic reference case is used, (3) the project is estimated at the entity level, and (4) no effects exist beyond your operations. Under these circumstances the emissions reduction estimate can be simply derived as the difference in your emissions for the reference case year and the reporting year. Both of these emissions levels are reported under the emissions report.

Example 1.5 - Identifying Effects - Activity-Level Project Analysis

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Sonomo Electric, a municipal utility, replaced all its distribution transformers on a feeder with energy efficient transformers. If Sonomo focused its project analysis on the whole utility, the results of the efficiency program would not have been fully reflected, because other changes in the system might have obscured them. Consequently, Sonomo evaluated its project by analyzing only the feeder distribution system serving the affected transformers.

Example 1.6 - Identifying Effects - Effects Outside the Utility

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

An electric utility, Salisbury Electric Power (SEP), undertook an industrial sector electrotechnology project that involved replacing its customer's coal-fueled aluminum smelting plant. It also undertook several unrelated projects to increase its own electricity generation efficiency. SEP used an entity-level analysis to capture the full effects of its own activities. It also identified the reduced emissions resulting from the aluminum smelter's switch from coal to electricity as an effect and quantified that effect. The methodology for quantifying emission reductions for electrotechnologies is discussed in the industrial sector document.

1.3.3 Estimate Emissions Reductions

The last step in analyzing greenhouse gas emissions-reducing projects is to estimate emissions for the reference case and the project case. This involves measuring or estimating energy use for each type of fuel that is consumed and for the energy conservation measures, relating them back to the net decrease in greenhouse gas emissions. In general, the level of emissions resulting from the production, delivery, and use of electricity depends on the four factors listed below. Note that the various emissions reductions activities in the electricity supply sector are each aimed at one of these four components:

- carbon content of the primary fuel (**emissions/unit of energy**). Fuel switching changes emissions per unit of energy.

- combination of technologies used to capture emissions before their release to the environment (**1 - the emissions removal efficiency**). Precombustion and postcombustion fuel technologies remove gases from the emission stream or prevent their creation in the first place.

- efficiency of the processes for producing and delivering energy to the point of use and conversion into the service demanded **(units of energy produced/unit service demand)**. Improvements in heat rate, controls, dispatch, and T&D reduce the amount of electricity that is lost between generation and use.

- total level of service demanded **(service demand level)**. Reductions in demands for electricity, through DSM programs and electricity energy conservation programs reduce the service level demand.

The following equation expresses the relation of energy-related emissions to these various components in the electricity supply sector. Example 1.7 illustrates the use of this equation in estimating emissions first for the reference case, then for the project case. The difference between the two estimates is the emissions reduction you may report.

$$\begin{aligned}\text{Emissions level} = {} & \text{(emission/unit of energy)} \\ & \bullet\ \text{(1 - emissions removal efficiency)} \\ & \bullet\ \text{(units of energy produced/unit service demand)} \\ & \bullet\ \text{(service demand level)}\end{aligned}$$

1.4 Sector-Specific Types of Emissions Reduction Projects

The previous section presented general approaches for analyzing projects in the electricity supply sector, including estimation methods for direct emissions. This section and the next two sections focus on specific types of projects and analytical approaches appropriate to each.

- Section 1.5 discusses projects that reduce direct emissions: fuel substitution and direct carbon removal.

- Section 1.6 focuses on projects that reduce emissions indirectly: equipment upgrades, operational improvements, integration of energy supply, and reduction in demand or energy losses. These projects include electricity conservation projects, DSM activities, and T&D efficiency improvements.

Example 1.7 - Estimating Emissions Reductions

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Wisconsin Integrated Power operated one pulverized coal-fired power plant that had no carbon dioxide removal technologies. Annual generation had been consistently at 2 million megawatt hours. In response to anticipated environmental regulations, the utility decided to install an amine carbon dioxide scrubbing unit with a 90 percent carbon dioxide removal efficiency. It also undertook a T&D project that reduced losses from the 15 percent level to a more efficient 10 percent, and a DSM project that reduced energy demand 3 percent. Using the equation discussed above, Wisconsin Integrated estimated, first, reference case emissions, then project case emissions. *[Note: The amine carbon dioxide scrubbing unit was selected for illustrative purposes only. No such units are known to be in commercial operation at this time in the United States, although some recent studies indicate limited applications in Japan (DOE 1991). As this and other CO_2 removal technologies become cost effective, they may see greater use.)*

Basic reference case emissions

From Table 1.3, the utility obtained the carbon dioxide emissions per unit of electrical energy produced, as follows:

$$1970 \text{ lbs } CO_2/\text{MWh} = 893 \text{ kg } CO_2/\text{MWh}$$

Wisconsin Integrated calculated its basic reference case, for the year 1990:

$$\begin{aligned}\text{Emissions}_{ref} &= (893 \text{ kg } CO_2/\text{MWh}) \bullet (1.0 - 0.0 \text{ emissions removal}) \\ &\quad \bullet (1.00 \text{ unit of energy produced}/0.850 \text{ unit of energy demand}) \bullet (2.00\text{x}10^6 \text{ MWh/yr}) \\ &= 2.10\text{x}10^9 \text{ kg } CO_2/\text{yr} \\ &= 2.10\text{x}10^6 \text{ metric tons } CO_2/\text{yr.}\end{aligned}$$

It confirmed this calculation to within 1.5 percent, using the approach described in Section 1.2 on emissions reporting. The calculation also agreed with the utility's past reports to EIA. This served to increase the utility's confidence in the accuracy of this approach.

Project case emissions

For the project case Wisconsin Integrated calculated

$$\begin{aligned}\text{Emission}_{proj} &= (893 \text{ kg } CO_2/\text{MWh} \bullet (1.00 - 0.90 \text{ emissions removal}) \\ &\quad \bullet (1.00 \text{ unit of energy produced}/0.900 \text{ unit of energy demand}) \\ &\quad \bullet (1.94\text{x}10^6 \text{ MWh/yr}) \\ &= 193.\text{x}10^6 \text{ kg } CO_2/\text{yr} \\ &= 193.\text{x}10^3 \text{ metric tons } CO_2/\text{yr.}\end{aligned}$$

Emissions reductions

Wisconsin Integrated calculated its emissions reduction:

$$\begin{aligned}\text{Emissions reduction} &= \text{Emission}_{ref} - \text{emission}_{proj} \\ &= 2.10\text{x}10^6 \text{ MT } CO_2/\text{yr} - 0.193\text{x}10^6 \text{ MT } CO_2/\text{yr}\end{aligned}$$

Electricity supply components, technologies and systems may be *direct* emitters of greenhouse gases or may be *indirectly* responsible for emissions through factors associated with their use. Direct emitting components are principally the plants that produce electricity using heat supplied by fuel combustion. Components that indirectly contribute to greenhouse gas emissions include all end-use loads that receive power from such plants and all electricity generation, transmission, and distribution equipment that causes energy losses that must be made up by additional power generation.

Appendix 1.B lists efficiency improvement, or energy conservation measures that indirectly reduce emissions in the electricity supply sector. Types of these activities are listed in Table 1.3, along with references to subsequent subsections that discuss appropriate estimation methods.

1.4.1 Project Types

The project types listed in Table 1.2 are grouped according to the electricity supply subsystem (generation, and transmission and distribution), and are categorized according to the type of activity: fuel substitution, direct carbon removal, and generation and T&D efficiency improvements. The project types are discussed in more detail after the table.

Table 1.2. Electricity Sector Activities Discussed in this Supporting Document

Type of Project	Activity	Section	Estimation Method
Direct (generation subsystem)	fuel substitution	1.5	IPCC (1991)/EPA (1990) EPA Acid Rain Program (49 CFR 75) measurement
Indirect/efficiency improvements (generation subsystem)	equipment upgrades operational improvements integration of energy supply	1.6.1	measurement engineering estimation
Indirect/efficiency improvements (transmission and distribution subsystem)	reduction in demand reduction in energy losses	1.6.2	measurement engineering estimation Dirkes, et al. 1993 BPA SCALE EPRI DSAS

Fuel substitution. Substituting non-fossil or low-emission fossil fuels for high-emission fossil fuels reduces emissions per unit of energy. Generation-side activities that lead directly to emissions reductions include introduction of renewables and replacement of a coal-fired plant by natural gas-fired units.

Energy efficiency improvements. The amount of primary energy required to provide a unit end-use energy service can be reduced through use of more efficient energy conversion, transfer, and end-use technologies. Energy efficiency improvement projects may include reducing losses in electricity generation, conversion, and transfer, in addition to reducing the energy required by end-use equipment to satisfy a given level of service demand.

1.4.2 Choice of Estimation Methods

Methods for estimating energy conservation and emissions reductions in the electricity supply sector include a broad range of approaches and techniques. The procedures for reporting and verifying the energy savings discussed in this guidance are flexible enough to accommodate standard conservation technologies as well as new developments in efficiency, fuel switching, and renewable technologies. You may report the estimation methods you use, whether or not those methods are included in this guidance.

Your choice of estimation methods may be constrained by the availability of data. For example, you may estimate emissions reductions from an energy efficiency project using measured data as well as engineering estimation. Using several methods and comparing the results may increase the credibility of your estimations.

1.5 Estimating Emissions Reductions for Direct Fuel Substitution Projects

This section presents standard methodologies for estimating reductions from projects involving direct emissions. The methods are applicable to both carbon dioxide and non-carbon dioxide greenhouse gases and can be used to compute emissions from carbon content or from various technologies employed in the electricity supply sector. The approaches also apply to analyses that use either a basic or modified reference case.

Substituting non-fossil or low-emission fossil fuels (natural gas or renewables) for high-emission fossil fuels will reduce total carbon dioxide emissions because of the variability of emission rates among primary fuels.

As described in Section 1.3.2, the effects of a project or group of projects can be evaluated by examining changes in emissions for your entire organization (entity-wide estimation) or for a more limited subset of your operations (activity-level estimation). This section discusses two approaches for entity-wide estimation of carbon dioxide emissions—one approach for activity-level estimation of carbon dioxide emissions reductions (the same approach presented in Section 1.2) and one for reductions in emissions of other greenhouse gases (using EPA's Acid Rain Methodology). The third approach discussed addresses non-carbon dioxide emissions reductions.

For fuel substitution projects, you can estimate the amount of greenhouse gas reductions using direct measurement (before and after the project), engineering estimation methods, or compilation of data on fuel use and default values. Savings may be derived using default values for emissions based on fuel types, as currently collected by utilities and reported to EIA and EPA, and default values for representative types of fuels and utility boiler sources. Generally, you will compute the net reduction in emissions by subtracting the after-project fuel emissions from the reference case emissions.

You may wish to report other aspects of your combustion process. For example, some generators recycle coal ash for use in making cement. In this case, the use of recycled material should be analyzed as an industrial sector project.

1.5.1 Estimating Carbon Dioxide Emissions Reductions: Modified IPCC Methodology

To estimate, on an entity-wide basis, the difference between the project case and the reference case, you may use the same 4-step, modified IPCC approach that was discussed in Section 1.2 for estimating emissions. Here, however, you will be performing two sets of calculations: one for the reference case and one for the project case. The difference between the two will be your reportable emissions reductions. (This is the same procedure described in Examples 1.6 and 1.7). For a basic reference case, you will calculate entity-wide emissions for a historical year; for a modified reference case, you will perform calculations on the basis of what emissions would have been without the project.

As described in Section 1.2, the amount of carbon dioxide emitted by an entity is directly related to the amount of fuel consumed, the fraction of fuel that is oxidized, and the carbon content of the fuel. For example, coal contains close to twice the carbon of natural gas and roughly 25 percent more than crude oil per unit of useful energy. Therefore, the approach for estimating emissions of carbon dioxide from fossil fuels is somewhat different from the approach used for estimating other greenhouse gas emissions, since carbon dioxide emissions depend mostly on the basic fuel characteristics, rather than on technology or emissions controls (as with such gases as nitrous oxide or carbon monoxide).

Estimating carbon dioxide emissions for the whole entity requires a careful accounting of fossil fuel consumption by type and carbon content of fossil fuels consumed. The methodology for estimating carbon dioxide emissions represents a top-down approach, rather than the bottom-up approach recommended for other greenhouse gases.

The methodology is illustrated in Example 1.8 (data drawn from Appendix 1.C).

Example 1.8 - Generation-Side Fuel Substitution: Modified IPCC Methodology

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Southwestern Utility decided to convert 30 percent of its coal generation mix to natural gas. First, the utility needed to calculate monthly utility-wide carbon dioxide emissions. Since the project was motivated not by increasing demand (which was flat) but by financial and dispatching considerations, Southwestern decided to use a basic reference case.

Step 1. For the basic reference case, staff used their monthly fuel consumption and heat content data reported on FERC Form 423 to derive the utility's carbon emissions, using the following relationship:

$$\sum_a E_a = FC_a \bullet CECo_a \bullet 0.99 \bullet 3.67$$

Fuel	Monthly Fuel Consumption	Energy Conversion Factors	Monthly Energy Consumption (PJ)	Emissions Conversion Factors (kg C/GJ)	Monthly Carbon Emissions (10^3 MT)
Liquid oil	646×10^3 bbl	1 bbl = 5.8×10^6 Btu	3.75×10^{12} Btu = 3.96 PJ	20.0	79.20
Solid coal	962×10^3 MT	1 MT coal = 22×10^6 Btu	21.16×10^{12} Btu = 22.32 PJ	25.8	575.86
Gases natural gas	2.404×10^3 MCF	1 MCF = 1.030×10^6 Btu	2.48×10^9 Btu = 0.0026 PJ	15.3	39.78×10^{-3}
Total monthly carbon emissions					**655.10**

bbl = barrels; MCF = thousand cubic feet; MT = metric tons; PJ = petajoule = 1×10^{15} J; GJ = gigajoule = 1×10^9 J

Note that Southwestern used the identity (derived from Table A.5 in Appendix A)

$$PJ = 0.9480\times10^{12} \text{ Btu}$$

to convert from Btu to PJ.

Because only 99 percent of the total carbon emissions is oxidized, and the ratio of carbon dioxide to carbon on a weight basis is 3.67 (see Appendix D), the monthly emissions of carbon dioxide for the reference case was

$$CO_2 \text{ emissions} = (655.10\times10^3 \text{ MT C}) \bullet (0.99) \bullet (3.67 \text{ MT } CO_2/\text{MT C})$$
$$= 2.38\times10^6 \text{ MT } CO_2$$

Example 1.8 - (cont'd)

Step 2. Southwestern then computed its monthly utility-wide carbon dioxide emission for the fuel substitution (project) case:

Fuel	Monthly Fuel Consumption	Energy Conversion Factors	Monthly Energy Consumption (PJ)	Emissions Conversion Factors (kg C/GJ)	Monthly Carbon Emissions (10^3 MT)
Liquid oil	646×10^3 bbl	1 bbl = 5.8×10^6 Btu	3.75×10^{12} Btu = 3.96 PJ	20.0	79.20
Solid coal	695×10^3 MT	1 MT coal = 22×10^6 Btu	15.29×10^{12} Btu = 16.13 PJ	25.8	416.15
Gases natural gas	6657×10^3 Mcf	1 Mcf = 1.030×10^6 Btu	6.86×10^{12} Btu = 7.24 PJ	15.3	110.77
Total monthly carbon emissions					**606.12**

bbl = barrels; MCF = thousand cubic feet; MT = metric tons; PJ = petajoule = 1×10^{15} J; GJ = gigajoule = 1×10^9 J

Southwestern then converted its project case monthly total carbon emissions to carbon dioxide emissions using the same method as for the reference case.

$$CO_2 \text{ emissions} = (606.12 \times 10^3 \text{ MT C}) \bullet (99 \text{ percent}) \bullet (3.67 \text{ MT } CO_2/\text{MT C})$$
$$= 2.20 \times 10^6 \text{ MT } CO_2$$

Step 3. Southwestern then determined its monthly emissions reductions:

$$\text{Emissions reduction} = \text{Emissions}_{ref} - \text{Emissions}_{proj}$$
$$= 2.38 \times 10^6 \text{ MT } CO_2 - 2.20 \times 10^6 \text{ MT } CO_2$$
$$= 0.18 \times 10^6 \text{ MT } CO_2$$

Step 4. Since carbon dioxide emissions during each month will be different, Southwestern finally determined its annual emissions reduction, E_{CO2a}, by summing the reductions achieved monthly during the year being reported:

$$E_{CO_2a} = \sum_{m=1}^{12} E_{CO_2m}$$

where E_{CO2a} = annual total CO_2 mass emissions reductions
E_{CO2m} = total CO_2 mass emissions reductions in month m

In the above example, Southwestern used the modified IPCC methodology, based on the carbon consent of the various fuels. Example 1.9 illustrates a technology-based approach, using the stipulated factors given in Table 1.3.

Table 1.3. Stipulated Carbon Dioxide Emissions from Selected Fossil Technologies

Technology	Heat Rate Btu/kWh	Stipulated CO_2 Emissions Factors	
		lb/MMBtu	lb/MWh
Uncontrolled PCF	9,500	207	1,970
PCF/Wet FGD	9,850	213	2,100
PCF/NOXSO	9,850	207	2,040
IGCC	8,730	207	1,810
AFBC	9,750	221	2,150
PFBC	8,710	229	1,990
Oil Steam	9,460	181	1,710
Gas Steam	9,580	115	1,100
NGCC	7,570	115	870
STIG	8,100	115	930
ISTIG	7,260	115	830

KEY: PCF = pulverized - coal-fired; FGD = flue gas desulfurization; IGCC = integrated coal-gasification combined cycle option; AFBC = atmospheric pressurized fluidized-bed combustion; NGCC = natural gas combined cycle; STIG = steam injection turbine; ISTIG = intercooled STIG.
lbs/MMBtu = pounds per million Btu of heat input; lbs/MWh = pounds per million megawatt hours of electrical generation.

Source: DOE/PE-0101 1991 (Table 2.5, page 2.10).

Example 1.9 - Fuel Substitutes - Renewables: Technology-Based Approach

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

The Quality Electric Development Utility (QED) recently issued a Request for Proposals (RFP) to private developers for a renewable electric power facility. The new facility was required to increase the utility's generating capacity in order to meet a projected modest increase in demand. The winning proposal from All-American Wind Generators, Inc., specified a wind farm with generating characteristics closely matching the projected demand increase. The power generated by the wind farm deferred the construction of a small, intermediate load, pulverized-coal-fired facility by QED. The coal facility would have produced 1,400 GWh annually.

Step 1. Determine emissions for the modified reference case from Table 1.3. Carbon dioxide emissions per unit of energy are

$$1{,}970 \text{ lbs } CO_2/\text{MWh} = 893 \text{ kg } CO_2/\text{MWh}.$$

Step 2. Determine emissions for the project case. Emissions from a wind turbine are 0.

Step 3. The pulverized coal plant would have produced 1,400 GWh annually. The wind facility produces 350,000 MWh annually. Assuming these 350,000 MWh replaced a like quantity of energy from the pulverized coal facility, the emissions reduction would be

$$(893 \text{ kg } CO_2/\text{MWh}) \bullet (350{,}000 \text{ MWh/yr}) = 313\text{x}10^6 \text{ kg } CO_2/\text{yr} = 313{,}000 \text{ MT/yr}.$$

Hence, the use of wind turbines resulted in 313,000 MT/yr of avoided CO_2 emissions.

1.5.2 Entity-Wide Estimation of Carbon Dioxide Emissions Reductions: EPA's Acid Rain Methodology

EPA's Acid Rain Program requires utilities to establish CEM systems for measuring emissions of sulfur dioxide and nitrogen oxides. It also requires utilities to report their carbon dioxide emissions, based on continuous measurements or estimation. Starting in April 1995, almost all U.S. utilities will be required to report their emissions of carbon dioxide and nitrogen oxides to EPA.

An increasing number of utilities are choosing to implement a continuous carbon dioxide monitoring system. When implemented, the continuous monitoring systems will provide important data on the actual amounts of greenhouse gas emissions by utilities. The data can then be used to verify greenhouse gas reduction levels. However, information is collected daily or monthly, so the initial calculations must be made on that basis, then aggregated to annual totals.

EPA's Acid Rain Program rules (40 CFR Part 75, Appendix G) outline procedures for estimating carbon dioxide emissions from the combustion of fossil fuels for each combustion unit, based on two methods: carbon content of fuel burned and CEM systems. The total carbon dioxide emissions from the utility is the sum of the emissions for each combustion unit.

To calculate daily carbon dioxide mass emissions in tons/day, based on carbon content of fuel method, use the following equation (taken directly from EPA's Acid Rain Program rules):

$$W_{CO_2} = 11/6{,}000 \bullet W_C$$

where W_{CO2} = carbon dioxide mass emissions in short tons/day
W_C = carbon burned, lb/day.

Example 1.10 - Estimation of Annual Carbon Dioxide Mass Emissions Reductions for a Coal-Fired Unit From Daily Data

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a coal-fired unit consumes 1,000 short tons of bituminous coal per day. Weekly coal analysis determined that the carbon content of this coal is $1.3\text{x}10^6$ lb/day. (See EPA's Acid Rain Program rules for the standard test method for carbon and hydrogen in the analytical sample of coal and coke, ASTM D3178-89.) *[Note: At this time, technologies for producing cleaner burning coal may not be cost-effective. Such a technology is referred to here for illustrative purposes only.]*

The coal-fired unit calculated daily carbon dioxide mass emissions, using the relationship and substituting its own physical data:

$$\begin{aligned} W_{CO_2} &= 11/6{,}000 \bullet W_C \\ &= 11/6{,}000 \bullet (1.3\text{x}10^6) \\ &= 2.4\text{x}10^3 \text{ short tons per day} \\ &= 2.4\text{x}10^3 \bullet 365 = 876\text{x}10^3 \text{ short tons per year} \end{aligned}$$

The coal-fired unit's estimated emissions were $876\text{x}10^3$ short tons per year. If the plant substituted cleaner burning coal and wished to report emissions reductions, the reporter would perform this calculation again for the cleaner coal, then determine the difference between the two.

Monthly carbon dioxide emissions may also be calculated, as in the following example.

Example 1.11 - Estimation of Annual Carbon Dioxide Emissions Reductions From Monthly Data

Note: *This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.*

Tri-States Electric Utility consists of 20 separate power plants, including coal, gas, and petroleum generation units. To calculate the monthly carbon dioxide emissions, the utility followed three steps (using conversion factors and default data from the tables in Appendixes A and 1.C):

Step 1. Tri-States estimated total carbon content in all fuels for one month.

Fuel	Consumption	Monthly Energy Consumption	Emissions Coefficient (kg C/GJ)	Total Carbon (Gg)
Liquid petroleum	3,000 bbl	1 bbl = 5.8×10^6 Btu 17.4×10^9 Btu = 0.018 PJ	20.0	0.36
Solid coal	252,000 ST	1 ton = 24×10^6 Btu $6{,}048 \times 10^9$ Btu = 6.4 PJ	25.8	165.12
Gases natural gas	2.048×10^3 MCF	1 MCF = 1.030×10^6 Btu 2.1×10^9 Btu = 0.002 PJ	15.3	0.03
TOTAL				165.51 Gg C

bbl = barrels ST = short tons MCF = thousand cubic feet PJ = petajoules = 0.9480×10^{12} Btu

Step 2. Tri-States then converted its total carbon emissions to CO_2 emissions, assuming a 99 percent oxidization rate and using the conversion factor described in Appendix D.

$$\text{Total monthly } CO_2 \text{ emissions} = 165.51 \text{ Gg C} \bullet (44 \text{ Gg } CO_2/12 \text{ Gg C}) \bullet (0.99) = 600.80 \text{ Gg}$$

The total monthly carbon dioxide emissions were 600.80 Gg.

To report emissions reductions from changes in the fuel mix, Tri-States would perform the same calculations for the project case and determine the difference between the two emissions levels to derive monthly emissions reductions.

Example 1.11 - (cont'd)

Step 3. Tri-States finally determines its annual emissions reduction, E_{CO2a}, by summing the reductions achieved monthly during the year being reported:

$$E_{CO_2a} = \sum_{m=1}^{12} E_{CO_2m}$$

where E_{CO2a} = annual total CO_2 mass emissions reductions
E_{CO2m} = total CO_2 mass emissions reductions in months

To report emissions reductions from changes in the fuel mix, Tri-States would perform the same calculations for the project mix and determine the difference between the two emissions levels.

Depending on equipment used and/or data collected, the estimation approach illustrated in Example 1.11 might be varied in a number of ways. For example, when the combustion unit uses emissions controls, the total carbon dioxide emissions (in tons) is the sum of combustion-related emissions and sorbent-related emissions. (See Appendix G of the Acid Rain Program.) If the generator has installed a CEM system, Appendix F of the Acid Rain Program outlines procedures to convert CEM system measurements of carbon dioxide concentration and volumetric flow rate into carbon dioxide mass emissions (in tons/day).

Example 1.11 illustrated how a utility could report its emissions reductions using an entity-level analysis. This is a particularly convenient approach for utilities who are already reporting emissions, and who use a basic reference case in their project analysis, because it does not require any additional data. However, not all electricity generators will report their entity-wide emissions. In those cases, the reporter may use an activity-level analysis, as shown in Example 1.12.

Example 1.12 - Project-Level Emissions Reductions Analysis: Efficiency Improvement

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

CK/MGJ, Inc., an independent power producer recently renovated one of its natural gas-fired electricity generation plants.

CK/MGJ repowered the plant, and experienced an efficiency improvement from 25 percent to 30 percent, representing a nearly 17 percent drop in natural gas consumption and a 15 percent capacity improvement. The owners calculated their emissions reductions at the activity level, using a basic reference case. They do not anticipate any other significant effects.

Step 1. For the basic reference case, CK/MGJ determined the carbon content of the fuel combusted, using the utility's historic natural gas consumption figures (1.2 PJ/yr) and the emissions conversion factor for natural gas from Appendix B (15.3 kg C/GJ).

$$\text{Emissions}_{ref} = (1.2\ \text{PJ/yr}) \bullet (15.3\ \text{kg C/GJ}) \bullet (1\text{x}10^{6}\ \text{GJ/PJ}) \bullet (1\text{x}10^{-6}\ \text{Gg C/kg C})$$

$$= 18.36\ \text{Gg C/yr}$$

Step 2. CK/MGJ calculated that a 17 percent drop in fuel consumption combined with the 15 percent capacity increase, resulted in a project case natural gas consumption of (1.2 PJ/yr • 0.83 • 1.15), 1.1454 PJ/yr, a net drop of 4.55 percent. This implied that carbon emissions had also dropped to 17.52 Gg C/yr.

Step 3. CK/MGJ calculated that its emissions reduction for this project was:

$$\text{Emissions Reduction} = \text{Emission}_{ref} - \text{Emission}_{proj}$$

$$= 18.36\ \text{Gg C/yr} - 17.52\ \text{Gg C/yr}$$

$$= 0.835\ \text{Gg C/yr}.$$

The company converted this to metric tons of carbon dioxide per year using the conversion factor from Appendix D:

$$\text{Carbon dioxide emissions reduction} = 0.835\ \text{Gg C/yr} \bullet 10^{3}\ \text{metric tons/Gg} \bullet 3.67\ \text{Gg } CO_2\text{/Gg C}$$

$$= 3.064\ \text{metric tons } CO_2\text{/yr}.$$

The next example, also an analysis at the activity level, illustrates the use of Table 1.3's stipulated data that express emissions of carbon dioxide per energy input to various types of technologies.

Example 1.13 - Project-Level Emissions Reduction Analysis: Boiler Replacement

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Mid States Power and Light replaced one pulverized coal plant with a natural gas combined cycle (NGCC) technology, both of which produced 1,000 GWh annually. From Table 1.3, the utility determined the following stipulated factors:

Coal CO_2 emissions coefficient = 689 lbs/mmBtu
Heat Rate = 9,750 Btu/KWH
Production = 1,000 GWH/yr

Heat Rate • Production = Annual Heat Input
9,750 Btu/kWh • 1,000 GWH/yr = 9.75×10^6 mmBtu/yr

Annual Heat Input • CO_2 emissions coefficient = Annual CO_2 emissions
9.75×10^6 mmBtu/yr • 689 lbs/mmBtu = 6.72×10^9 lbs/yr

NGCC CO_2 emissions coefficient = 115 lbs/mmBtu
Heat Rate = 7,570 Btu/KWH
Production = 1,000 GWH/yr

Heat Rate • Production = Annual Heat Input
7,570 Btu/KWh • 1,000 GWH/yr = 7.57×10^6 mmBtu/yr

Annual Heat Input • CO_2 emissions coefficient = Annual CO_2 emissions
7.57×10^6 mmBtu/yr • 115 lbs/mmBtu = 871×10^6 lbs/yr

Using the general equation

$$\text{Emissions reduction} = \text{Emissions}_{ref} - \text{Emissions}_{proj}$$

the utility substituted the stipulated factors:

$$\text{Emissions reduction} = (6.72 \times 10^9) - (871 \times 10^6) = 5.85 \times 10^9 \text{ lbs/yr}$$

The reduction in carbon dioxide emissions is therefore 5.85×10^9 lbs/yr. Note that the same GWH are assumed before and after the change in technologies.

Sources: DOE (1983), Northwest Public Planning Council (1991).

1.5.3 Estimation of Non-Carbon Dioxide Emissions Reductions

Estimation of emissions other than carbon dioxide from combustion generation units can be time consuming and complex. The simplest method is the modified IPCC method, outlined in Section 1.3, "Direct emissions of a mix of greenhouse gases." Table 1.1 lists representative stipulated factors for non-carbon dioxide greenhouse gases, methane (CH_4), nitrous oxide (N_2O), by principal technology and fuel type. Note that, unlike carbon dioxide emissions estimates, estimates of non-carbon dioxide emissions are based on technologies used, not fuel carbon content alone. Use the methods described in

Section 1.3 to estimate emissions for both the reference case and the project case. Emissions reductions are simply the difference between the two.

1.6 Energy Efficiency Improvements

This section provides guidance for engineering estimates and default-derived energy savings from energy efficiency projects related to generation, transmission, distribution, and end-use. Generation-side projects are described in subsection 1.6.1; however, estimation methods are not discussed, since the estimations may be made using methods detailed in Section 1.5 for direct emissions. T&D projects are described in subsection 1.6.2, along with some appropriate estimation methods. These projects reduce emissions indirectly, so an extra step will be required to determine emissions reductions at the point of generation (see Section 1.7).

1.6.1 Generation-Side Energy Efficiency Improvements

This subsection presents types of projects that result in emissions reductions from energy efficiency improvements from generation activities. To determine appropriate reference cases for these projects, you need to carefully consider where other effects may be occurring and how large they are relative to the project's obvious, intended effects (see the discussion in Section 1.3.2). To estimate emissions reductions from these projects, you could use the same approaches discussed for direct projects (Section 1.5).

On the generation side, projects can be categorized into improvements to plant operations and equipment, and integrated energy supply. Projects that involve equipment upgrades will help provide a larger percentage of "clean power" from a greenhouse gas perspective, thus reducing many of the pollutants under consideration. Improved operations of the energy control centers and dispatching practices, use of efficient controls and adjustments, and coordinated operation and planning systems are key elements to making effective and efficient energy choices that ultimately reduce greenhouse gases.

Entities can enhance the performance of some existing hydroelectric and nuclear plants by upgrading equipment, changing operation and maintenance practices, and improving training to increase the output. These improvements result in energy savings that reduce the emissions level of the system as a whole; therefore, an entity-level project analysis is appropriate.

An integrated or fuel-flexible energy supply involves combining separate energy supply technologies into integrated systems to provide multiple energy services at higher overall performance. Examples include cogeneration, fuel cells, and integrated energy storage networks. Key features of an integrated energy supply system include recovering or reusing waste heat and balancing peak and off-peak electrical or thermal loads.

Cogeneration is the joint production of electrical and thermal energy from an input fuel. This use of input energy for two separate output forms can result in higher overall energy conversion efficiencies. A system may supply electric power requirements as well as thermal energy for space heating, hot water, district heating, and industrial process heating. Project analysis for cogeneration is covered in the supporting document for the industrial sector.

Fuel cells convert the chemical energy of a fuel directly into electric power via an electrochemical reaction between hydrogen and oxygen. Depending on the cost and availability of input fuel, the electrical conversion efficiency from the input fuel to the electric power in fuel cells may be higher than conventional generation techniques.

Most energy storage systems do not emit greenhouse gases directly. Their use as components in the electricity supply sector can improve overall system efficiency and, therefore, can help lower emissions. Storage systems provide the ability to uncouple supply from end-use demand, which is important for flexibility in the choice of fuels. Some storage shaves peaks on a daily basis, others on a seasonal basis. In general, energy storage offers the potential to reduce emissions by reducing the need for additional energy conversion to meet a service demand. Principal applications of energy storage include utility load leveling in the following end-use sectors: electric vehicles, customer-side storage, and thermal energy management in buildings.

1.6.2 Transmission and Distribution Subsystem Energy Efficiency Improvements

Energy savings associated with reducing T&D losses can be realized by replacing the existing stock of equipment with more efficient units and components, by implementing more efficient system management practices, and by operational modifications.

Supply curves can be used to describe the conservation resource potentially available from T&D subsystem improvements and to estimate energy savings. Supply curves relate the levelized cost of upgrading existing equipment to the estimated amount of energy saved. Stated in this form, the resource represented by reducing T&D losses can be compared in the IRP process to other conservation options to determine the most cost-effective method of supplying power to the utility's customers. The IRP process is rapidly being accepted as the planning standard for utilities.

Approaches for improving T&D efficiency include reconductoring (replacing existing lines with larger-size conductors), replacing transformers, upgrading the voltage of distribution systems, and adding capacity.

Estimation of T&D energy savings based on a single activity

The existence and quality of data that characterize your T&D system will determine the quality of your estimates. If you have existing models of your T&D subsystems, then the effort involved in estimating the energy savings should be minimal. If you have a good database representing a portion of your

T&D system, then you will need to estimate the overall system characteristics. Any T&D energy savings (in the absence of other measures) should be reflected in the reduced levels of carbon dioxide emissions, which you may be continuously reporting to the EPA under the Acid Rain Program.

The following two component categories contribute to the majority of total T&D system losses: *conductors* (feeders and transmission lines), and *transformers* (distribution systems and substations). Project activities may involve replacing a single unit, a number of units in a subsystem, or the entire system. Each of these component categories is discussed below.

Conductors. Conductor loss occurs primarily because of the resistance of the conducting materials (copper or aluminum) to the flow of electric current. In general, the smaller the diameter of the conductor, the greater the resistance to the flow of the current. Literature-derived values for conductor resistance [see, for example, the *Standard Handbook for Electrical Engineers* (Fowle 1993)] can be used to calculate feeder and transmission-line conductor losses.

For a project involving a single conductor segment,

$$\text{loss reduction} = \text{conductor loss}_{\text{reference}} - \text{conductor loss}_{\text{replacement, larger size}}$$

A standard conductor loss methodology (IEEE 1994; Tepel, Callaway, and DeSteese 1987) is used to calculate annual conductor losses. The following equation can be used to calculate the annual energy loss, on a per unit basis, for a single conductor (feeder or transmission line) segment:

$$L_L = 8.76\,(p)^2\,(r)\,(LSF)/(kV)^2$$

where L_L = line losses in Watt-hours per year per circuit mile
p = peak apparent power in kVA
r = conductor resistance in ohms per mile
LSF = loss factor, which ranges between 0.2 and 0.6
kV = voltage in kilovolts.

Typically, you will evaluate the economic feasibility of upgrading a segment of a conductor by computing annual conductor costs for two conductor sizes. You determine the economic range of operation by computing peak current as a function of loss factor, LSF, where LSF varies from 0.2 to 0.6, and with conductor size as a parameter (IEEE 1994). If you have undertaken a reconductoring project, you have determined all the parameters you need to compute energy savings.

Example 1.14: Replacement of Feeder Conductor: Reduction of Conductor Losses

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Knowlton Electric, a utility, estimated that, within its distribution system, the 12.5 kV overhead feeder consists of a medium size, 2/0 AWG (American Wire Gauge), ACSR (aluminum). According to the *Standard Handbook for Electrical Engineers* (Fowle 1993), this feeder has a resistance of 0.89 ohm/mile.

To reduce losses, the feeder conductor was replaced with aluminum conductor that was three sizes larger (266.8 kcmil, where kcmil is thousand circular mils), which has a resistance of 0.385 ohm/mile when operating at 50 degrees C and 60 Hz [*Standard Handbook for Electrical Engineers* (Fowle 1993)].

To estimate annual energy savings from reconductoring, Knowlton used the conductor equation to estimate emissions from both the reference case and the project case:

Reference Case

$$\begin{aligned} L_L &= 8.76\,(p)^2\,(r)(LSF)/(kV)_2 \\ &= 8.76\,(2531)^2\,(0.89)(0.2)/(12.5)^2 \\ &= 63.9 \text{ kWh/circuit mile/yr} \end{aligned}$$

Project Case

$$\begin{aligned} L_L &= 8.76\,(p)^2\,(r)(LSF)/(kV)_2 \\ &= 8.76\,(2531)^2\,(0.385)(0.2)/(12.5)^2 \\ &= 27.7 \text{ kWh/circuit mile/yr} \end{aligned}$$

The annual energy savings = 63.9 - 27.7 = 36.2 kWh/circuit mile/yr.

To compute annual emissions reductions, Knowlton multiplied the annual energy savings by the appropriate emissions factor (see Section 1.7), and the number of circuit miles in its system.

The previous discussion and Example 1.14 used a methodology for a *single* feeder/transmission line segment. For a *collection* of feeder/transmission line segments, the resultant loss can be estimated using the following equation:

$$SUMLOSS_n = (KLOSS_n)\,(RR_n)\,(TLEN_n)$$

where $SUMLOSS_n$ = sum of the calculated losses for sample lines, in MWh per year for size group n
$KLOSS_n$ = constant size group n
RR_n = "real" resistance closest to size group n average resistance
$TLEN_n$ = total length of line in size group n, in circuit miles.

For the *entire entity*, use the following equation:

$$LOSS_n = (RR_n)(KLOSS_n)(DF)$$

where $LOSS_n$ = loss per circuit mile of line in MWh per year for size group n
DF = distribution factor (estimated at 0.765 for feeders, 1.0 for transmission lines).

Finally, the per-unit loss reduction (annual energy savings) from a high-efficiency replacement conductor project is equal to the difference between the per-unit losses for the reference components and per-unit losses for the replacement components. Details about methodology can be found in Tepel, Callaway, and DeSteese (1987).

Transformers. Transformers generate losses in two ways. Coil loss (also known as copper loss or load loss) is caused by the impedance to the flow of current in the transformer windings when supplying an electrical load. The second source of loss results from hysteresis and eddy currents in the steel core of the transformer, which are independent of the load. This loss is referred to as a core loss, or no-load loss.

Following are examples of projects that can be undertaken to reduce transformer load and no-load losses:

- Replace transformers with amorphous core transformers (load loss improvements).
- Replace transformers with improved silicon steel core transformers (load loss improvements).
- Replace transformers with amorphous core transformers and improved winding efficiency (load and no-load loss improvements).
- Replace transformers with improved silicon steel core transformers and improved winding efficiency (load and no-load loss improvements).

The total transformer losses may be expressed as

$$P_{loss} = P_L + P_{NL}$$

where P_{loss} = the total transformer loss
P_L = the load loss
P_{NL} = the no-load loss.

The load loss term can be expressed as

$$P_L = \sum_{\text{all } i} (I_i^2 R_i)$$

where I_i = the current in winding i
R_i = the resistance of winding i.

To estimate transformer losses, you may follow standard methodology (IEEE 1994; Fowle and Knowlton 1993; Dirks et al. 1993). Example 1.15 illustrates the use of this methodology. Several computer models have been developed to calculate annual transformer losses. One such model is XFMR (Dirks et al. 1993).

To compute total annual energy losses for the reference case transformer, first determine annual no-load and annual load losses. Since no-load losses continue throughout the year, they are estimated as

Annual no-load losses = 8760 hrs/yr • (no-load loss expressed in kW)

Load losses for transformers are estimated by an empirical relationship that accounts for the variability of transformer load throughout the year and the fact that load losses vary with the square of the transformer current. Annual load losses are estimated by

Annual load losses = 8760 hrs/yr • loss factor • (rated load losses expressed in kW)

The loss factor is typically assumed to be between 0.2 and 0.6. For additional guidance, see IEEE 1994.

Tables in Dirks et al. (1993) present the full-load performance data for a number of transformers representative of the designs typically encountered in the utility power system. You may use your own data or these tables to estimate savings for your transformer replacement project.

Included in each table (Dirks et al. 1993) are the full-load efficiency, all the losses modeled by the XFMR code, the percentage of the total thermal loss that each of the losses represents, and the percentage of the total electric loss represented by each loss. The tables list representative loss parameters for conventional core as well as amorphous core transformers. Transformers with amorphous cores offer the potential for greatly reduced core losses by increasing the resistivity of the core material. This increased resistivity reduces eddy currents in the core, and the amorphous structure greatly reduces hysteresis losses.

Example 1.15 - Project to Reduce Transformer Losses

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Norton Power and Light (NPL) replaced a 30 MVA conventional core grid transformer with an array equivalent to 30 MVA amorphous core transformers on a feeder.

Step 1. NPL estimated the basic reference case annual energy losses.

Dirks et al. (1993) provides the following:

Annual no-load losses = 8760 hrs/yr • (core loss + eddy-current coil + leakage loss + dielectric loss)

Annual no-load losses = 8760 hrs/yr • (20,030W + 70.23W + 3,116W + 1.587W) = 203 MWh

Annual load losses = 8760 hrs/yr • 0.6 • (55.54 kW • 0.42) = 122.6 MWh

Total annual loss for the reference case transformer = 203 MWh + 122.6 MWh = 325.6 MWh

Step 2. NPL then estimated the project case's annual energy losses.

For the project amorphous core transformers, annual no-load losses are provided in Dirks et al. (1993)

Annual no-load losses = 8,760 hrs/yr • (4,998W) = 43.78 MWh
Annual load losses = 8,760 hrs/yr • 0.6 • (59,390 kW • 0.42) = 131 MWh

The total annual loss for the project transformers = 174.78 MWh

Step 3. NPL then calculated annual energy savings.

$$\text{Total annual energy savings} = \text{annual losses}_{ref} - \text{annual losses}_{proj}$$

The total annual energy savings = 325.6 - 174.78 = 150.82 MWh

Step 4. Finally, the utility estimated emissions reductions by multiplying the total annual energy savings by the emissions factor (see Section 1.7).

Annual losses per transformer based on the Westinghouse/EPRI methodology (Westinghouse 1981) can be estimated using the following equation:

$$LT = 8.76\,(NLL + LL(PLR^2)\,(LSF))$$

where LT = annual loss in kWh per year (distribution) and in MWh (substation), per transformer
NLL = no-load loss, watts (distribution), or kW (substation)
LL = load loss, watts, or kW
PLR = peak load ratio (ratio of peak kVA to rated kVA)
LSF = loss factor.

Estimates of T&D energy savings for utility-wide projects

The utility-wide T&D system losses are the difference between the average annual power requirements of a given utility and its annual sales. System-wide losses can be estimated using one of the following methods, which are described in Tepel, Callaway, and DeSteese (1987):

- The method described in the Bonneville Power Administration (BPA) *Distribution System Efficiency Improvement Handbook* (1981). This approach is presented in the form of a field estimating handbook. By using the tables and worksheets in this manual that account for major loss sources in a system, field personnel can compute losses with a hand calculator. This approach is useful for evaluating losses in a small portion of a system. However, it does not appear to be suitable for evaluating a complete distribution system or a regional subset of a system.

- A computer model, such as SCALE (Simplified Calculation of Loss Equations) (EPRI 1983). This method was developed for computer implementation. It incorporates equations and estimating techniques that are generally accepted in the industry.

- Detailed calculation of distribution losses (EPRI 1983). This method requires a very large database, including metered substation energy and end-use billing for a year, and 24-hour profiles for transformers serving each class of consumers. The difference between energy entering the system and that received by consumers is attributed to losses.

- The DSAS (Distribution System Analysis and Simulation program) method (Sun et al. 1980). This method was developed by the Energy Systems Research Center at the University of Texas at Arlington, Texas. It integrates daily load shapes with a load flow procedure to produce an energy model. Feeder performance is analyzed by a load flow program capable of modeling different load component characteristics, load imbalances, and system configuration. This is probably the most rigorous method.

Following is an approach for estimating energy savings from T&D activities for an entity-wide project, based on the SCALE model. Details of this methodology and calculations for the case of BPA can be found in *Customer System Efficiency Improvement Assessment* (Tepel, Callaway, and DeSteese 1987). (References to tables below are from this source.)

1. Estimate numbers and types of T&D components: distribution transformers, substation transformers, primary feeders, and transmission lines (Table 3.4).

2. Establish operating characteristics of the reference case stock of components and the project stock (Table 4.1, 4.2, 4.3, and 4.4).

3. Calculate losses for the reference case stock (Table 4.5).

4. Calculate losses for the project stock (Table 4.5).

5. Calculate energy savings = losses (reference case stock) - losses (project stock) (Table 4.5).

Load management. Distribution system management practices that can reduce energy consumption include voltage regulation techniques collectively called conservation voltage reduction (CVR). CVR is, in principle, the regulation of distribution feeder voltages so that the load furthest from the substation is maintained at the minimum acceptable voltage under all load conditions on the circuit. This practice slightly reduces the average feeder voltage without affecting the function of customer equipment connected to the circuit. A modest load management effect is achieved by this voltage reduction because of the corresponding reduction in average end-use energy consumption.

In general, load management options reduce loads and modify end-use load shapes to produce an aggregate reduction in system peak load. Therefore, load management options present an alternative to constructing peaking plants and additional T&D capacity.

Data needs for load management include customer class loads, end-use loads, end-use load shapes, number of components, and load components. Load data should be separable into end-use sectors (residential, commercial, and industrial). Time-of-day data are needed to construct load shapes. Shape information is needed to estimate the effects of conservation and load management options on system peaks. End-use metered data are preferable. If no metered data exist for the project area, either meters can be installed or data can be borrowed from another area and normalized for differences in weather and customer characteristics. Data normalization requirements introduce extensive additional information needs regarding customer characteristics and weather. Utilities generally can provide numbers of customers by customer class, loads, and load forecasts. In the BPA area, for example, utilities provide all these data, as well as load forecasts, to the BPA on BPA Form 980.

Because the effects of load management are dispersed throughout the system, estimation of their effects on emissions of greenhouse gases is best carried out through project analysis at the entity level.

1.7 Converting Energy Reductions to Emissions Reductions

Several activities reported in this and other supporting documents are evaluated in terms of energy savings. For example, the evaluation of improvements in line losses expresses results in megawatt hours per year. Similarly, DSM projects are generally evaluated for electricity savings. Electric vehicle projects described in the transportation sector support document express energy changes in terms of decreases in liquid fuels and increases in electricity consumption. Evaluation of cogeneration projects involves estimation of utility electricity generation displaced by the project. For purposes of this reporting program, however, you must carry the analysis one step further.

Estimating reductions in electricity consumption is only the first step in estimating reductions of greenhouse gas emissions. The electricity savings must be traced back through the transmission and generation system to gauge how emissions change in a "mapping" process. This mapping process produces electricity emissions factors that provide a ratio for changes in emissions of greenhouse gases to changes in electricity consumption.

The mapping process can be quite complicated. Different generating resources have different greenhouse gas production characteristics. Nuclear power and renewable-energy sources, such as hydroelectric, wind, and solar power, produce emissions approaching zero, whereas natural gas, oil, and coal-powered electric-generating stations produce significant greenhouse gas emissions (with natural gas typically producing the least and coal the most). Since electric utility loads vary with the time of day and season, utilities will typically have several plants that they phase in and out of service. These plants are used (or dispatched, in industry terms) based on economics and other factors. Depending upon availability, the plant that produces power at the lowest cost will usually be dispatched first, and the plant that produces power at the highest cost will be dispatched last.

The greenhouse gas reduction depends on which plant's production is reduced to accommodate the reduced load resulting from the conservation measure. This mapping problem is complicated by time-of-day and magnitude issues.

The greenhouse gas emissions depend on the generating plant mix and how that mix is affected by the measure. If the base load plant is nuclear and the peaking plant is natural gas-fired, then reducing the peak load while increasing the base load would reduce greenhouse gas emissions. On the other hand, if the base load plant is coal and the peaking plant is natural gas, then reducing the peak load while increasing the base load will increase greenhouse gas production.

Emissions factors are very useful tools for estimating emissions of air pollutants. However, because they are averages obtained (in some cases) from data of wide range and varying degrees of accuracy, emissions calculated this way for a given project are likely to differ from that project's actual emissions. Because emissions factors are averages, they will indicate higher emissions estimates than are actual for some sources, lower for others. Only direct measurement can determine the actual pollutant contribution from a source, under existing conditions. For the most accurate emissions estimate, you should obtain source-specific data whenever possible.

Two types of emissions factors can be readily used for the voluntary reporting program: default values provided by DOE and emissions factors calculated from the generating mix of the utility. In general, reporters in the electricity supply sector will likely have specific data from which to derive project-specific or site-specific factors. The default factors will be useful to reporters, generally, in other sectors, who do not have ready access to generation data.

1.7.1 Default Factors

The default emissions factors contained in Appendix C are the simplest to use relative to the other methods of calculating emissions. However, you should realize that these default factors will either underestimate or overestimate the actual emissions characteristics of any given power-generating equipment, as they represent the average emissions characteristics over a state.

For the purposes of the voluntary reporting program, and to retain flexibility and ease-of-use, Appendix C provides default state-level electrical emissions factors for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Three factors are given for each state: one for emissions from utility generation, one for emissions from nonutility generation, and one combined utility/nonutility. If you know the source for your electricity (that is, utility or nonutility), you may use the appropriate factor. If you do not know or if you use both utility and nonutility sources, you should use the combined factors for your state. See Appendix C to this volume for more information.

1.7.2 Calculated Factors

To increase the accuracy of your reports, you may choose to calculate emissions factors, based on generating data specific to your situation. For example, you may choose to develop an emissions factor linking an individual DSM program or an hourly and daily basis to the marginal unit it is affecting. Or you may choose to be less specific, for example, applying a fossil or baseload/intermediate/peak average to an individual program or set of programs.

Average emissions factors for a group of generators can be based on the measured characteristics of the individual generators for the time period affecting the energy-saving activities, as illustrated in Example 1.16.

Example 1.16 - Estimation of Emissions Using a Calculated Emissions Factor

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

For this example, assume that three plants operate on different cycles to provide power, as described in the first table below. The generating mix, operating schedules, and emissions factors are for illustrative purposes only and may not reflect the actual conditions for any utility.

Calculate average emissions factors by the hour. After the data in the first table below are aggregated, the average emissions are obtained, as shown in the second table.

Generating Characteristics

Generating Plant	Operation Schedule	CO_2 Emissions[a] (lb/MWh)	Generation (MWh)
Pulverized Coal	24 hours	1,970	4,000
Gas Fired Combined Cycle	2-7 p.m.	1,300	1,500
Flash Geothermal	24 hours	160	100

Average Hourly Emissions Factors

Schedule	Emissions Factors (lb CO_2/MWh)
Base load: 12 a.m. to 2 p.m. and 7 p.m. to 12 a.m.	1,926
Peak Load: 2 p.m. to 7 p.m.	1,758
Daily average	1,891

The average daily emissions factors are 1,891 lb carbon dioxide per MWh of generation, assuming that the peak period lasts 5 hours. The total carbon dioxide emissions are calculated as

$$\begin{aligned}\text{Total } CO_2 \text{ Emissions} &= (CO_2 \text{ Emissions Factor}) \bullet (\text{Generation}) \\ &= (1{,}891 \ \frac{\text{lb } CO_2}{\text{MWh}}) \bullet (5{,}600 \text{ MWh}) \\ &= 10.59 \text{ million lb or } 5{,}295 \text{ short tons of } CO_2\end{aligned}$$

(a) Source: WAPA 1994.

In comparison to the default factors, the advantage of using the calculated factors is that they can be specifically tailored to match the energy-conservation characteristics of the activities being implemented, such as the time of day and the season of the year. In fact, this method could provide a more accurate emissions factor for certain activities than using measured factors, especially if the measured factors were a representative mean of all hours and generating plants for a specific utility. This approach has the highest credibility when it is used to assimilate data from individually monitored generating facilities into an activity-specific emissions factor.

1.7.3 Degree of Aggregation

You may report energy-efficiency savings that result from projects at various levels of aggregation. For fossil fuel savings, the level of aggregation is not important. For electrical savings, where time-of-day factors influence emissions reductions, it is important. You could report aggregate savings data for all T&D activities. Conversely, you may report at a more specific, disaggregated level—for example, delineating the savings by category of project (transformers, conductors, etc.).

Savings delineated by category may result in more accurate estimates of greenhouse gas emissions through the mapping process than aggregate data, because with aggregate data, mapping will estimate diurnal impacts based on archetypical load profiles. However, reporting at the aggregate level may be easier for many entities.

1.8 Existing Reporting Programs

You may also use data that are currently reported to other programs or used for other purposes in preparing your submissions under this voluntary reporting program. Appropriate data on current and past energy consumption by utilities, including both fuel tonnage and the energy content, reported to EIA and the Federal Energy Regulatory Commission (FERC) by domestic utilities. Utilities are required to report both the coal rank, the energy content, and the amount of the coal they burn. These data are compiled as follows:

- The EIA collects detailed monthly and annual reports on energy consumption in the electricity sector. A list of reports is provided in Appendix 1.A. Form EIA-767, Steam Electric Plant Operation and Design Report, includes information on fuel consumption and fuel quality, as well as information on flue gas desulfurization. Form EIA-861, Annual Electric Utility Report, includes information on energy sources, peak demand, and non-utility power producers, as well as DSM energy and peak reduction effects.

- Pursuant to the Clean Air Act Amendments of 1990, the Acid Rain Program establishes requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions to the EPA. Carbon dioxide emissions may be reported based on EPA-provided estimation methodology or continuous monitoring. EPA's Acid Rain Program must certify all CEM systems as well as any alternative monitoring systems.

- IRPs contain data and analysis of the environmental considerations associated with resource alternatives considered, on both the supply and the demand sides.

Some utility industry associations also collect energy data from their members for internal purposes. For example,

- Edison Electric Institute collects energy data from its investor-owned utility members.

- The American Public Power Association collects energy data from its public sector utilities.

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Appendix 1.A

EIA Data Collected for the Electricity Supply Sector

EIA Data Collected for the Electricity Supply Sector

Consumption	EIA-457A/H	Residential Energy Consumption Survey
	EIA-759	Monthly Power Plant Report
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-871A/F	Commercial Buildings Energy Consumption Survey
Costs and/or Prices	EIA-871A/F	Commercial Buildings Energy Consumption Survey
Disposition	EIA-826	Monthly Electric Utility Sales and Revenue Report with State Distributions
	EIA-861	Annual Electric Utility Report
	FE-781R	Annual Report of International Electrical Export/Import Data
Financial and/or Management	EIA-254	Semiannual Report on Status of Reactor Construction
	EIA-412	Annual Report of Electric Utilities
	EIA-826	Monthly Electric Utility Sales and Revenue Report with State Distributions
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-860	Annual Electric Generator Report
	EIA-861	Annual Electric Utility Report
	FERC-1	Annual Report of Major Electric Utilities, Licensees and Others
	OE-411	Coordinated Regional Bulk Power Supply Program Report
	OE-417R	Power System Emergency Reporting Procedures
Production	EIA-759	Monthly Power Plant Report
	EIA-767	Steam-Electric Power Plant Operation and Design Report
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-860	Annual Electric Generator Report
	EIA-861	Annual Electric Utility Report
	EIA-867	Annual Nonutility Power Producer Report
	FERC-1	Annual Report of Major Electric Utilities, Licensees and Others
	OE-411	Coordinated Regional Bulk Power Supply Program Report
Research and Development	EIA-846A/D	Manufacturing Energy Consumption Survey
Supply	EIA-759	Monthly Power Plant Report
	FE-781R	Annual Report of International Electrical Export/Import Data
	OE-411	Coordinated Regional Bulk Power Supply Program Report

Source: EIA, Directory of Energy Data Collection Forms.

Appendix 1.B

Energy Conservation Measures in the Electricity Supply Sector

Energy Conservation Measures in the Electricity Supply Sector (excerpted from EPA Acid Rain Program Rule)

2. Supply-side Measures Applicable for Reduced Utilization

Supply-side measures that may be approved for purposes of reduced utilization plans under § 72.43 include the following:

2.1 Generation efficiency

- Heat rate improvement programs
- Availability improvement programs
- Coal cleaning measures that improve boiler efficiency
- Turbine improvements
- Boiler improvements
- Control improvements, including artificial intelligence and expert systems
- Distributed control—local (real-time) versus central (delayed)
- Equipment monitoring
- Performance monitoring
- Preventive maintenance
- Additional or improved heat recovery
- Sliding/variable pressure operations
- Adjustable speed drives
- Improved personnel training to improve man/machine interface

2.2 Transmission and distribution efficiency

- High efficiency transformer switchouts using amorphous core and silicon steel technologies
- Low-loss windings
- Innovative cable insulation
- Reactive power dispatch optimization
- Power factor control
- Primary feeder reconfiguration
- Primary distribution voltage upgrades
- High efficiency substation transformers
- Controllable series capacitors
- Real-time distribution data acquisition analysis and control systems
- Conservation voltage regulation

3. Renewable Energy Generation Measures Applicable for the Conservation and Renewable Energy Reserve Program

The following listed measures are approved as "qualified renewable energy generation" for purposes of the Conservation and Renewable Energy Reserve Program. Measures not appearing on the list may also be qualified renewable energy generation measures if they meet the requirements specified in § 73.81.

3.1 Biomass resources

- Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste.

3.2 Solar resources

- Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
- Grid and non-grid connected photovoltaic systems, including systems added for voltage or capacity augmentation of a distribution grid.

3.4 Geothermal resources

- Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.

3.5 Wind resources

- Grid-connected and non-grid-connected wind farms
- Individual wind-driven electrical generating turbines

(The information requirements in this subpart have been approved by the Office of Management and Budget under the control number 2080-0221.)

In addition

3.6 Hydropower resource

- Conventional plants operate on the flow of water from storage reservoirs or free-flowing waterways
- Pumped storage plants pump water resource usually through a revariable turbine, from a lower reservoir to an upper reservoir.
- District heating and cooling systems
- Dispatching

Appendix 1.C

Background Data for IPCC/EPA Methodology, U.S. Data

Table C.1. Estimation of Total Carbon in Fuels

Fuel	Conversion Factor (GJ/tonne)	Carbon Emissions Conversion Factors (kg C/GJ)
Liquid Fuels (1000 metric tonnes)		
1. Crude Oil	42.71	20.0
2. Natl. Gas Liquids	45.22	20.0
3. Gasoline	44.80	18.9
4. Kerosene	43.75	19.5
5. Jet Fuel	44.59	20.0
6. Gas/Diesel Oil	43.33	20.2
7. Residual Oil	40.19	21.1
8. LPG	47.31	17.2
9. Naphtha	45.01	20.0
10. Petroleum Coke	40.19	20.0
11. Refinery F-stocks	42.50	20.0
12. Other Oil	40.19	20.0
Solid Fuels (1000 metric tonnes)		
13. Coking Coal	29.68	25.8
14. Steam Coal	26.45	25.8
15. Sub-bit, Coal	19.40	26.1
16. Lignite	14.15	27.6
17. Peat	20.10	28.9
18. Coke	27.47	25.8
19. Other Solid Fuels		25.8
Gaseous Fuels (Terajoules)		
20. Natural Gas (dry)	0.0009	15.3

LPG = Liquified Petroleum Gases; tonne = metric ton.

Source: IPCC (1991).

Residential and Commercial Buildings Sector

Part 2 of 6 Supporting Documents

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Examples

Figures

Tables

2.0 Residential and Commercial Buildings Sector

This document supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act (EPAct) of 1992. The General Guidelines provide the rationale for the voluntary reporting program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this supporting document, you should read the General Guidelines. Then read this document, which relates the general guidance to the issues, methods, and data specific to the residential and commercial buildings sector. Other supporting documents address the electricity supply sector, the industrial sector, the transportation sector, the forestry sector, and the agricultural sector.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon sequestration projects. When you understand the approaches taken by the voluntary reporting program, you will have the background needed to complete the reporting forms.

The General Guidelines and supporting documents address four major greenhouse gases: carbon dioxide, methane, nitrous oxide, and halogenated substances. Although other radiatively enhancing gases are not generally discussed, you will be able to report nitrogen oxides (NO_x), nonmethane volatile organic compounds (NMVOCs), and carbon monoxide (CO) after the second reporting cycle (that is, after 1996).

The Department of Energy (DOE) has designed this voluntary reporting program to be flexible and easy to use. For example, you are encouraged to use the same fuel consumption or energy savings data that you may already have compiled for existing programs or for your own internal tracking. In addition, you may use the default emissions factors and stipulated factors that this document provides for some types of projects to convert your existing data directly into estimated emissions reductions. The intent of the default emissions and stipulated factors is to simplify the reporting process, not to discourage you from developing your own emissions estimates.

Whether you report for your whole organization, only for one project, or at some level in between, you will find guidance and overall approaches that will help you in analyzing your projects and developing your reports. If you need reporting forms, contact the Energy Information Administration (EIA) of DOE, 1000 Independence Avenue, SW, Washington, DC 20585.

2.1 Residential and Commercial Buildings: Overview

In 1990, the residential and commercial buildings sector accounted for 24 percent of the natural gas, 7 percent of the fuel oil, and 65 percent of the electricity consumed annually in the United States. This represents 35 percent of all the primary energy consumed in the United States, and an expenditure of over \$192 billion dollars (EIA 1991). Included in the residential sector are all single family detached dwellings, multifamily dwellings, condominiums, townhouses, and manufactured homes. The commercial sector includes Federal government buildings, post offices, colleges and universities, hospitals, elementary and secondary schools, churches, and the non-residential buildings owned and operated by private businesses, including commercial buildings that are part of industrial and agricultural complexes.

The residential and commercial buildings sector does not include industrial or agricultural processes, which are covered in the supporting documents for those sectors.

2.1.1 Reporting Entities

This sector contains a wide range of potential reporters, from individuals to large organizations. On the residential side, reporters could include electric and natural gas utilities (especially from a demand-side management [DSM] perspective), consumer groups, Federal agencies, state governments, municipal housing authorities, multifamily complex owners, homeowners/renters, builders and developers, and energy service companies. The commercial side of the sector could include many of these same reporters, plus businesses, churches, industrial plants, educational institutions and individual schools—indeed, any entity that owns, operates, or provides energy-related services for buildings may report in this sector.

2.1.2 Sector-Specific Issues

Two factors create reporting challenges in this sector. The first is that many of the emissions reductions activities do not reduce emissions directly; instead, they cause reductions in energy demand or use energy more efficiently. Typically, that energy is in the form of electricity, so the energy savings must be traced back through the transmission and generation system to gauge how emissions change as a result of these activities. The second factor is that many potential reporters may be involved in the same or related activities that reduce emissions.

Estimating emissions reductions resulting from energy savings can be complicated. However, the process will be simplified if you use the default emissions factors supplied in Appendix B (for fuels) and Appendix C (for electricity); both appendixes are at the end of this volume. These default factors are not as accurate as factors specific to your site, because there is not a direct one-for-one relationship between energy production and greenhouse gas production. Different generating resources have different greenhouse gas production characteristics. Nuclear power and renewable energy sources such as hydroelectric, wind, and solar have essentially zero emissions whereas natural gas, oil, and coal (fossil fuels) powered electric generating stations produce significant greenhouse gas emissions (with natural gas typically producing the least and coal the most). If carbon flows are accounted for, biomass powered generation has a zero emissions factor.

Moreover, the generation mix changes from time to time. Since electric utility loads are not steady by hour of the day or by season, utilities will typically have several plants that they phase in and out of production to meet their loads. These plants are used or dispatched (in industry terms) based on economics. Depending upon availability, the plant producing power at the lowest marginal cost will be dispatched first and the plant producing power at the highest cost last.

This process is further complicated by time-of-day and magnitude issues. For example, building envelope and heating, ventilating, and air conditioning (HVAC) improvements reduce loads depending on weather, but retrofitting high-efficiency equipment and appliances cause reduced consumption whenever they are used.

Some technologies simply shift the load to another time period. For example, a thermal storage system shifts heating or cooling load from the utilities on-peak period to an off- or partial-peak period. The greenhouse gas impact depends entirely on the generating plant mix and how that mix is changed by the measure. For example, if the base load plant is nuclear and the peaking plant is natural gas fired, then reducing the peak load while increasing the base load would lead to reductions in greenhouse gas emissions. If the base load plant is coal and the peaking plant is natural gas, then reducing the peak load while increasing the base load could result in increased greenhouse gas emissions.

The potential for multiple reporting and joint reporting is another key issue in this sector. For example, a utility may wish to report energy savings data for its commercial lighting efficiency rebate program. A company that utilized the rebates offered by the electric utility may wish to report emissions reductions also. An organization that has two or more structural levels may wish to report at each level. Both agencies that promulgate and enforce building codes and standards and building owners who comply with the standards may wish to report resulting greenhouse gas emissions reductions. In some instances, you may wish to cooperate with other reporters to develop more complete reports than each of you could submit independently. At the least, you should identify other potential reporters of the same activity.

2.2 Estimating and Reporting Greenhouse Gas Emissions

The General Guidelines ("What is Involved in Reporting Emissions?") explain that reporting information on greenhouse gas emissions for the baseline period of 1987 through 1990 and for subsequent calendar years on an annual basis is considered an important element of this program. If you are able to report emissions for your entire organization, you should consider providing a comprehensive accounting of such emissions so that your audience can gain a clear understanding of your overall activities.

Your emissions may be direct (from fuel used on-site) or indirect (from grid-supplied electricity). To report direct emissions, determine your fuel use for the reporting year and use the table in Appendix B to calculate the emissions from that fuel use. To calculate emissions resulting from electricity use, you may use the default state level factors in Appendix C or calculate factors specific to your electricity source using the guidance in Section 2.8.

2.3 Analyzing Emissions Reduction Projects

Section 2.2 discussed estimating emissions; this section and the following sections provide guidance for analyzing and reporting projects that have reduced those emissions. This section provides an overview and rationale for the process, relating the General Guidelines to the residential and commercial buildings sector. The following sections discuss specific emissions-reducing measures and methods for estimating the reductions achieved.

Figure 2.1 presents a simplified view of the project analysis process in the residential and commercial buildings sector. This process is discussed in the General Guidelines; this and the following sections augment the general guidance with considerations specific to this sector.

Define the project. In the project definition step, you determine whether to report emissions levels for your whole organization (entity-level reporting) or some part of it. This decision may be based, in part, on what data you have, what effects are associated with the project (for example, will effects show up at the overall organization level?), and who the audience for your report will be (for example, will interested environmental groups find a partial report credible?).

The analysis of emissions reductions projects in the residential and commercial buildings sector consists of the basic steps that are discussed in the General Guidelines under the heading "How Should I Analyze Projects I Wish to Report?":

Establish a reference case to use as a basis for comparison with the project. You may determine your reference case in conjunction with defining your project, since you must establish a basis for comparison. If you wish to compare overall emissions from the project year with those of an earlier year, you may choose a basic reference case. If, however, your purpose is instead to highlight the effects of a specific emissions reductions project for which no historical comparison exists, you may choose a modified reference case.

Identify effects of the project. If you identify significant effects outside your current project boundaries, you may choose to redefine your project. In any case, you should identify all effects you are able to and, if they are large, quantify them to the extent possible.

Estimate emissions for the reference case and the project. If you have monitored data on your total emissions and you are reporting at the entity level, you are ready to report after you identify any external effects. Otherwise, whether emissions are direct or indirect may be important in choosing estimation methods. Direct emissions may be estimated from fuel consumption data and from stipulated factors associated with technologies used to generate electricity. However, many of the projects in this sector involve indirect emissions, especially activities whose purpose is to conserve electricity or reduce its use. Indirect emissions are estimated from energy savings data (for example, reducing the amount of electricity used to light buildings) that are then traced back to the generation system to determine the associated emissions reductions.

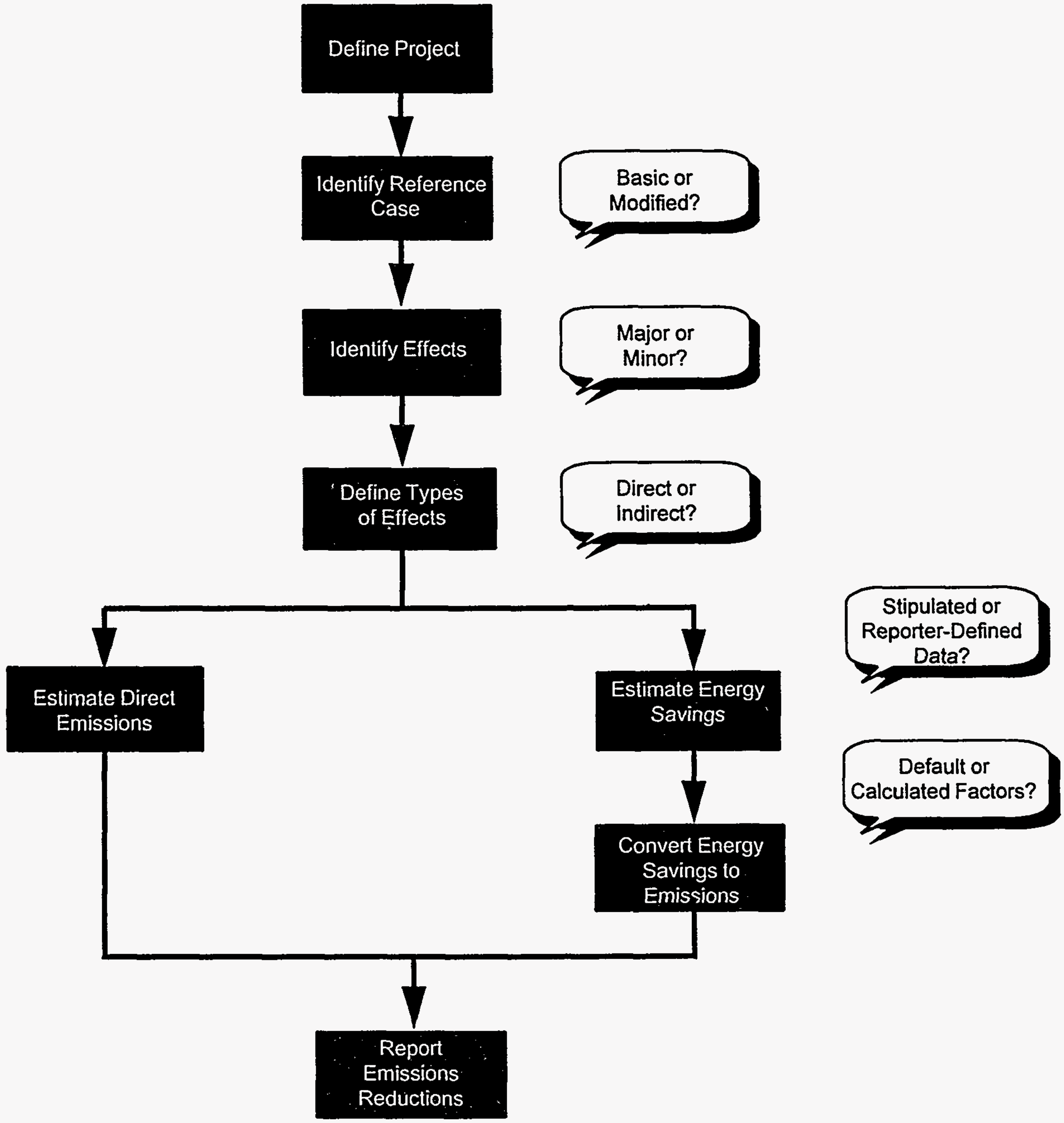

Figure 2.1. Many Projects in the Residential and Commercial Buildings Sector Involve Estimating Energy Savings and Converting Those Savings to Emissions Reductions.

The choice of method for estimating the effects of projects that act primarily on a single device or group of devices depends upon the nature and timing of the load involved. Loads can be categorized according to whether they involve constant or variable levels, and whether the hours that those loads occur are fixed.

Project analysis can be simple or complex, depending upon a number of factors involved in each step. This section discusses the major methodologies used to calculate emissions reductions, but you have the flexibility to choose how to define your project and reference cases and how to estimate emissions reductions. If you wish to report a standard project, you will find the descriptions of projects and the stipulated factors that you need in Section 2.6.1. If you intend to develop a reporter-designed project, you can use whatever methods you choose, providing your analysis and report meet the minimum reporting requirements described in the General Guidelines, "What Are the Minimum Reporting Requirements?"

2.4 Energy-Conservation Measures

A multitude of demand-side, energy-conservation activities can be applied in commercial and residential buildings to reduce energy use. In addition, new technologies are constantly being developed and marketed that increase the efficiency of mechanical and electrical systems in buildings. Some of these activities are listed in Table 2.1, along with pointers to the subsections that discuss appropriate estimation methods. The activities listed are further supplemented in Appendix 2.A. Project types not explicitly included in either list can be reported as long as they meet minimum project analysis and reporting requirements.

2.5 Estimation Techniques

Energy conservation in buildings includes a broad range of activities. No general protocols for verifying energy-conservation savings can anticipate every kind of conservation technology, program, or activity that can be undertaken by reporting entities. Therefore, procedures for verifying the energy savings must be flexible enough to accommodate verification of the common conservation measures as well as new developments in efficiency.

Flexibility is also important in addressing other emissions-reducing activities, such as fuel switching and renewable-energy technologies. Both of these types of activities can be estimated using any of the above techniques. For example, utility bill monitoring alone can provide accurate savings estimates for solar thermal projects where the original fossil fuel use was dedicated to the end-use requirement met by the solar system.

Following is a list of techniques currently in use; Appendix 2.B presents more information on each technique.

Table 2.1. Activities with a Basic Reference Case Discussed in this Supporting Document

Activities	Section	Estimation Methods
Constant Load with Fixed Hours		
High-Efficiency Motors with Constant Load	2.6.1	Engineering analysis Stipulated equations Stipulated savings Manufacturer's estimate Run-time meters with spot meters Run-time meters with end-use meters Billing history analysis Statistical analysis
Exit Sign Light Replacements		
Amorphous Metal Distribution Transformers		
High-Efficiency Refrigerators		
High-Efficiency Street Lights		
Water Heater Insulation Blankets		
Constant Load with Variable Hours		
Water Flow Restrictors	2.6.2	Run-time meters with spot metering Run-time meters with end-use metering
High-Efficiency Lights		
High-Efficiency Motors		
High-Efficiency Lights with Occupancy Sensors		
High-Efficiency Lights with Daylight Dimmers		
Constant Load: Fixed Hours to Variable Hours		
Occupancy Sensors	2.6.3	Run-time meters with spot metering End-use metering Post retrofit monitoring
EMS Demand Control,		
Direct Load Control		
Daylight Switch		
Variable Load		
Chillers	2.6.4	Short-term monitoring and calculation of part-load curves
Variable Speed Drives		
Variable Frequency Motors		
Daylight Dimmers		
Combination/Interactive Loads		
High-Efficiency Lighting	2.6.5	Billing history analysis Load research data analysis (whole building) Building simulation
High-Efficiency HVAC		
Building Shell Measures		
DSM Program Analysis		
	2.6.6	Billing history analysis Econometric models End-use metering Building simulation Statistical analysis

Engineering analysis. Engineering analyses are used to develop estimates of energy savings based on technical information from manufacturers in conjunction with assumed operating characteristics of the equipment.

Building simulation models. Building simulation models are really a collection of engineering equations. Building simulations can be used to develop end-use load shapes for utility forecasting and DSM planning, trade-off analysis for standards development, and estimation of energy savings from various energy-conservation activities.

Analysis of past utility bills. This technique can be used to develop a facility's baseline energy use. Energy savings are determined by comparing the metered energy use in the current year to the baseline year. For space heating and cooling, energy use can be normalized for weather changes. In addition, energy use figures may be adjusted to account for changes in site operations. Past utility bills can also be used in a statistical pre/post or normal/control framework.

Metering. Energy savings can be measured for specific equipment with fixed operating hours (spot metering), for specific equipment with variable operating hours (end-use metering), at the building or account level (metering or load-research data), or in pipes for a nonelectric fuel source (flow metering). Metering can also be used to record ambient weather conditions, such as outdoor temperature, humidity and wind speed, the actual temperature and humidity levels inside a conditioned space, and other parameters that are inputs for control systems (for example, the humidity level in an air duct).

Manufacturers' estimates. Several appliance manufacturers (refrigerators, water heaters, clothes washers and dryers, etc.) provide estimates of energy consumption in the form of Energy Guide labels.

Statistical analysis. Statistical analysis can be used in conditional demand models, econometric models, and weather normalization. Weather normalization is used to separate out the HVAC energy from the total energy use in the facility; this could be a requirement if billing history or load research data are used to examine the energy savings from an HVAC activity.

Hybrid techniques. Hybrid techniques combine one or more of the above methods to create an even stronger analytical tool.

2.6 Estimating Energy Savings for Projects with a Basic Reference Case

The basic reference case is based solely on historic levels of emissions. (Section 2.7 addresses projects involving a modified reference case.) The choice of estimation technique is influenced by the complexity of the energy conservation activity being implemented as well as the project definition. You may identify your project's primary effects as occurring at the level of a single activity or device, a group of similar activities, or a group of very dissimilar energy-efficiency activities.

The energy savings may be calculated at any desired level of aggregation (see Example 2.1). Some groups are best suited (or even restricted) to specific estimation techniques because of their load characteristics, such as fixed or variable operating hours, a constant or variable load, and a disaggregated or aggregated estimate.

Example 2.1 - Defining Projects and Effects

***Note:** This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.*

A commercial building owner and an electric utility may have different scopes for their projects' effects as described below:

- A commercial building owner may report greenhouse gas reductions in its facility at the device level (for example, separate activity classifications for greenhouse gas reductions resulting from high-efficiency lighting and lighting controls), for a group of devices (for example, the estimated greenhouse gas reductions from all lighting activities), or for a whole building (for example, estimated greenhouse gas reductions from lighting, HVAC, and all other energy-efficiency activities implemented at the facility).

- An electric utility may group its estimates into different categories—perhaps the same categories as it uses to report DSM program results. At a disaggregated level, a utility could report greenhouse gas reductions separately at the device level (for example, lighting control activities, high-efficiency lighting activities, HVAC efficiency activities, and HVAC control activities). Or, if the program is defined at the end-use level, it could report "program-level" estimates (for example, lighting program savings and HVAC program savings). Or the utility could define its program at a higher aggregate level (for example, commercial savings, residential savings, industrial savings).

The following load characteristics are useful for categorizing activities:

- constant load with fixed hours
- constant load with variable hours
- constant load: fixed hours to variable hours
- variable load
- combination/interactive loads
- demand-side management program analysis.

Based upon the load characteristics an activity exhibits, an appropriate estimation technique can be used to determine energy savings. Energy savings is defined as the difference between the project energy use with the activity in place and the reference case energy use, that is, the energy that would have been required had the project not taken place.

2.6.1 Constant Load with Fixed Hours

These activities run at a constant load either continuously throughout the year (with down time for maintenance) or on a fixed schedule (via time clocks, an energy management control system, or other scheduling control strategy). When your project involves changing only the load level and not the number of hours at which the load operates—that is, you are using a basic reference case and the hours of operation with your project are the same as those for your reference case—the following expression provides an estimate of your energy savings:

$$\text{Energy Savings} = H \bullet \left[P_{bref} - P_{proj}\right]$$

where Energy Savings = annual energy savings resulting from the project, in kWh
H = annual hours of operation
P_{bref} = power requirement, in kW, under the basic reference case
P_{proj} = power requirement, in kW, with the project.

If your project involves changing both the load level and the number of hours of operation from the basic reference case, the estimation must be modified as follows:

$$\text{Energy Savings} = \left[H_{bref} \bullet P_{bref}\right] - \left[H_{proj} \bullet P_{proj}\right]$$

where H_{bref} = the annual hours of operation in the basic reference case
H_{proj} = the annual hours of operation with the project.

Note that the above expression is simply another way of saying that the energy savings is the difference between energy use in the reference case and energy use with the project. This could also be expressed as follows:

$$\text{Energy Savings} = \left[E_{bref} - E_{prof}\right]$$

where E_{bref} = the annual energy use in the basic reference case
E_{proj} = the annual energy use with the project.

Example calculations

The following examples illustrate several cases where the devices exhibit constant loads with fixed hours both before and after the project. These approaches for estimating energy savings for constant-load applications that have fixed operating hours are best suited to single energy-conservation activities, as opposed to groups of energy-conservation measures that have different load characteristics.

Example 2.2 illustrates the use of engineering analysis for constant loads with fixed operating hours.

Example 2.2 - Engineering Analysis for Relighting with High-Efficiency Fluorescent Fixtures

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A retail store replaced 100, 3-lamp, 8-foot standard fluorescent fixtures that have a standard magnetic ballast with 96, two-lamp, high-efficiency fluorescent fixtures that have electronic ballasts. The store lighting was on a fixed schedule: 100 percent of the lights are on from 6 a.m. until 9 p.m. Monday through Friday, 8 a.m. until 10 p.m. on Saturday, and 11 a.m. until 7 p.m. on Sunday.

First, the store identified a basic reference case using the operating characteristics of the lighting system immediately before the project's implementation. This reflected an assumption that the lighting system would have continued to operate unchanged, but for the intervention of the project.

Second, the store identified the effects of this project. The most obvious effect was to decrease electricity use for lighting; another effect was that the more efficient light generates less heat. This latter effect is generally positive during a cooling season and negative during the heating season.

Third, the store estimated the energy savings, using the following five steps:

Step 1. Determine the power before and after the activity, using the following equation:

$$P = \text{Rating} \bullet \text{Number of Fixtures}$$

where P = required power
Rating = rated power (from manufacturer's data).

For the basic reference case, the power was estimated as

$$\begin{aligned} P_{bref} &= 273 \text{ Watts} \bullet 100 \text{ Fixtures} \\ &= 27.3 \text{ kW} \end{aligned}$$

After the project, the power requirement was

$$\begin{aligned} P_{proj} &= 108 \text{ Watts} \bullet 96 \text{ Fixtures} \\ &= 10.4 \text{ kW} \end{aligned}$$

Step 2. Determine the annual hours of operation for the fixtures. Based on the schedules identified above, the annual operating hours were estimated to be 5,058 hours per year.

Step 3. Calculate the annual energy savings:

$$\begin{aligned} \text{Energy Savings} &= H \bullet [P_{bref} - P_{proj}] \\ \text{Energy Savings} &= 5{,}058 \text{ hours} \bullet [27.3 \text{ kW} - 10.4 \text{ kW}] \\ &= 85{,}500 \text{ kWh} \end{aligned}$$

Step 4. Estimate the magnitude of the heating effect. The determination of cooling bonus vs. heating penalty was primarily a function of the heating and cooling system efficiencies. For this example, the effect is assumed to be negligible.

Step 5. Calculate the estimated reduction in emissions associated with the energy savings (85,500 kWh), as discussed in Section 2.8).

The chief advantages of using the engineering analysis described in Example 2.2 are its simplicity and low cost, relative to more complex estimation techniques. However, an inexpensive improvement can be made to the energy savings estimate by performing short-term monitoring with run-time meters to obtain an improved estimate of annual operating hours and by using spot metering to measure the instantaneous power requirements before and after the activity has been implemented, as illustrated in Example 2.3.

Example 2.3 - Run-Time Meters with Spot Meters for Relighting with High-Efficiency Fluorescent Fixtures

***Note:** This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.*

An alternative method of obtaining the annual hours of operation in Example 2.2 is to use a run-time meter to monitor the actual average hours of operation for the fixtures that are being retrofitted. Assume that a run-time meter is placed on the desired lighting circuit and that the annual hours of operation are found to be 5,170 hours. Spot meters measure the old power requirement as 26.8 kW and the new power requirement as 10.9 kW. The energy savings can now be estimated as

$$\begin{aligned} \text{Energy Savings} &= H \bullet [P_{bref} - P_{proj}] \\ &= 5{,}170 \text{ hours} \bullet (26.8 \text{ kW} - 10.9 \text{ kW}) \\ &= 82{,}203 \text{ kWh} \end{aligned}$$

Again, the estimated reduction in emissions associated with this energy savings can be computed as discussed in Section 2.8.

The main advantage of using the run-time and spot meters relative to the engineering analysis is the increased accuracy. In addition, these types of meters are inexpensive, leading to small cost increases. However, to be more accurate and increase the credibility of the results, end-use metering should be considered as an alternative, as shown in Example 2.4.

End-use (and load-research) meters record the continuous demand requirements of an energy-consuming device or electrical circuit and report the results at specified intervals. (Electrical demand meters typically use a 15-minute interval). The reported power requirements are integrated over the monitoring period to obtain the energy use for that period. Finally, the energy use for the period needs to be extrapolated to estimate the annual energy use for the energy-consuming device. While the end-use meter provides a more accurate energy savings estimate relative to the other techniques, it is also the most expensive.

Example 2.4 - End-Use Metering of Devices or Circuits

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

If the activity is monitored both before and after implementation, the annual energy savings can be calculated using the following equation:

$$\text{Energy Savings} = [E_{bref} - E_{proj}]$$

If the E_{bref} were found to be 143,170 kWh, and the E_{proj} were estimated at 52,300 kWh, then the annual savings would be estimated as

$$\text{Energy Savings} = [143{,}170 \text{ kWh} - 52{,}300 \text{ kWh}]$$
$$= 90{,}870 \text{ kWh}$$

Again, the estimated reduction in emissions can be computed as discussed in Section 2.8.

Standard projects and stipulated factors

This subsection provides specific factors and calculations for estimating the energy savings for the following projects:

- high-efficiency motors with constant load
- exit sign light replacements
- amorphous metal distribution transformers
- high-efficiency refrigerators
- higher-efficiency street lights
- water heater improvements.

The specific factors and calculation methods use the Environmental Protection Agency's (EPA's) Conservation Verification Protocols (CVPs) approach, which allows electric energy savings from these types of activities to be calculated using stipulated savings equations.

For a more detailed overview of the assumptions and source references, see *Conservation Verification Protocols: A Guidance Document for Electric Utilities Affected by the Acid Rain Program of the Clean Air Act Amendments of 1990* (EPA 1993). Although the EPAct Section 1605(b) voluntary reporting program does not disallow or require any specific estimation techniques such as the CVPs, default equations and factors are presented here. Thus, for the purpose of this reporting program, these are defined as standard projects.

High-efficiency motors with constant load. This activity applies to motor upgrades or retrofits of standard motors being used to power a continuous load for at least 8,500 hours a year. The energy savings can be calculated as follows:

$$\text{Energy Savings} = 8{,}500 \bullet \left(P_{bref} - P_{proj}\right)$$

where Energy Savings = annual energy savings resulting from the activity, in kWh

8,500 = number of operating hours per year, assuming 3 percent average down time for maintenance

P_{bref} = power consumption of existing motor (in kW)

P_{proj} = power consumption of new motor (in kW).

Exit sign light replacements. In most situations, exit signs are required to operate 24 hours a day. As an energy-conservation measure, the existing incandescent fixture is replaced by either fluorescent fixtures or light-emitting diodes. The savings can be calculated as follows:

$$\text{Energy Savings} = 8{,}760 \bullet \left(P_{bref} - P_{prof}\right)$$

where Energy Savings = annual energy savings resulting from the activity, in kWh
8,760 = number of operating hours per year
P_{bref} = power consumption of existing exit sign (in kW — typically 0.03 kW)
P_{proj} = power consumption of new exit sign, in kW).

Amorphous metal distribution transformers. No-load losses can be reduced by 60 to 70 percent over those found in conventional silicon-steel transformers. This reduction in loss occurs during every hour of the year. The savings can be calculated as follows:

$$\text{Energy Savings} = C^{0.75} \bullet 3.1 \times 10^{-3} \bullet 8{,}760$$

where Energy Savings = annual energy savings resulting from the activity, in kWh
8,760 = number of hours per year
C = rated capacity of replaced transformer (in kVA)
3.1×10^{-3} = decrease in no-load losses per unit capacity$^{3/4}$ (in kW/kVA$^{3/4}$).

High-efficiency refrigerator replacement. This activity involves replacing an existing refrigerator with a higher-efficiency unit and removal of the old unit from service. The savings for a single refrigerator can be calculated as follows:

$$\text{Energy Savings} = E_{bref} - E_{proj}$$

where Energy Savings = annual energy savings resulting from the activity, in kWh
E_{bref} = energy use of old refrigerator (kWh per year) = 750 kWh per year
E_{proj} = annual energy use of new refrigerator from the energy label.

Higher-efficiency street lights. This activity involves replacing existing street lighting fixtures with higher-efficiency lighting fixtures. The annual energy savings is calculated as follows:

$$\text{Energy Savings} = 4{,}000 \bullet \left(P_{bref} - P_{proj}\right)$$

where Energy Savings = annual energy savings resulting from the activity
4,000 = operating hours per year
P_{bref} = power consumption of old lighting fixtures, in kW
P_{proj} = power consumption of new lighting fixtures, in kW.

Energy-conservation measures for residential water heaters. This activity involves wrapping a residential electric water heater storage tank with an insulating blanket, anti-convection valves to reduce the standby losses, and adding pipe insulation. The expected electric energy savings for the activities are shown in Table 2.2.

Table 2.2. Expected Electricity Savings from Water Heater Conservation Measures

Activity	Expected Savings (kWh/Year)
Insulation Blanket Around Tank	400
Anti-Convection Valves	200
Pipe Insulation	200
Source: *Conservation Verification Protocols* (EPA 1993)	

2.6.2 Constant Load with Variable Hours

These activities are assumed to run at a constant load on a variable (or unknown) schedule throughout the year. While business hours are known, the hours of operation for energy-consuming appliances may not be known, even for indoor lighting. For example, one activity that people may not consider when estimating their lighting hours of operation is the presence of cleaning crews in their facility. A typical tracking mechanism that cleaning crews use to know which rooms have been cleaned is to enter the facility after business hours and turn on all of the lights in the facility; after cleaning the rooms, they turn off the lights. Other factors include employees forgetting to turn off lights when they leave. These types of behaviors can result in inaccurate estimates of hours of operation. Some of the energy-conservation activities that fall in this category include the following:

- water-flow restrictors
- high-efficiency lights
- high-efficiency motors
- high-efficiency lights with occupancy sensors
- high-efficiency lights with daylight dimmers.

If the hours of operation are highly variable or not controlled, then simple engineering analysis alone cannot be used to accurately estimate the annual energy savings. The two methods that work best for this type of estimation are run-time meters with (1) spot metering and (2) end-use metering. Examples 2.5 and 2.6 illustrate these techniques for projects where there is a constant load with variable hours both before and after the project, and analysis is based on a basic reference case.

Example 2.5 - Run-Time Meters for High-Efficiency Production Motors

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a manufacturing facility planned to upgrade a line of production motors (20 motors, 10 hp, 75 percent efficiency) with smaller, high-efficiency (7.5 hp, 85 percent efficiency) motors. These motors operated at a constant loading of 6 horsepower (or 60 percent) each, but the production schedule was not fixed. A basic reference case was defined, based on the operating characteristics of the motors for the three months immediately prior to the project. To estimate the annual energy savings, the following steps are necessary.

Step 1. Estimate annual operating hours. Run-time meters were put in place on 5 of the 20 motors (that were representative of all the motors) for three months and measured an average of 1,435 hours of operation. Extrapolating the results to a single year and assuming 3 percent down time in the course of a typical year implied that each motor operates 5,568 hours per year.

Step 2. Calculate the power consumption of the motors for both the reference case and the project using the following equation:

$$P = \left(\frac{hp \bullet \text{load factor}}{\eta}\right) \cdot 0.746 \frac{kW}{hp}$$

where P = power requirement of the motor (in kW)
hp = rated horsepower of the motor
load factor = ratio of actual load on motor over rated load
η = full-load efficiency of the motor (a more accurate approach is to obtain the actual efficiency at the particular loading condition from the manufacturer).

The reference case power requirement was

$$P_{bref} = \left(\frac{10 \text{ hp} \bullet 0.6 \text{ loading}}{0.75}\right) \cdot 0.746 \frac{kW}{hp}$$
$$= 6.0 \text{ kW per motor}$$

The power requirement with the project was

$$P_{proj} = \left(\frac{7.5 \text{ hp} \bullet 0.8}{0.85}\right) \cdot 0.746 \frac{kW}{hp}$$
$$= 5.3 \text{ kW per motor}$$

Step 3. Calculate the energy savings:

$$\text{Energy Savings} = 5{,}568 \text{ hours} \bullet 20 \text{ motors} \bullet (6.0 \text{ kW} - 5.3 \text{ kW})$$
$$= 77{,}950 \text{ kWh}$$

Step 4. Calculate the greenhouse gas emissions reductions (see Section 2.8).

Example 2.6 - End-Use Meters for High-Efficiency Production Motors

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

The other method that could be used for constant loads with variable operating hours is to monitor the energy use of each of the motors for a couple of representative months before and after the activity is in place, extrapolate the results to an annual basis, and calculate the estimated energy savings. In Example 2.5, a sample of motors would have had its energy use monitored for two to three months, both before and after the motors were changed. The reference case and project energy use would have been extrapolated to annual usages, and the energy savings would have been calculated using the equation from Section 2.6.1:

$$\text{Energy Savings} = \left[E_{bref} - E_{proj}\right]$$

Again, the greenhouse gas emissions reductions would then have been computed as discussed in Section 2.8.

2.6.3 Constant Load: Fixed Hours to Variable Hours

Sections 2.6.1 and 2.6.2 discussed situations where the load is constant and hours were either fixed or variable. The examples used illustrations where both the reference case and the project had the same type of hours. But it is also possible to undertake projects where the hours change from fixed before the projects—that is, in the basic reference case—to variable after the project. This type of activity occurs when the scheduling of a load on a device is changed with respect to some defined condition, generally by adding a controlling mechanism, such as occupancy sensors, an energy management control system, or some other controls. While the previous hours of operation (before the schedule change was implemented) were known, the new hours of operation are not known. Some of the energy-conservation technologies that cause a device to fall in this category include the following:

- occupancy sensors
- EMS demand control
- direct load control
- daylight dimmers.

This category of loading includes activities that change the schedule of operation but not the loading on the device (such as variable-speed drives), which is covered under variable loading. Two methods that are particularly effective for this type of estimation are run-time meters with spot metering (Example 2.7), and end-use metering (Example 2.8).

Example 2.7 - Run-Time Meters with Spot Meters for Occupancy Sensor Controls

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a retail store had 96, two-lamp, high-efficiency fluorescent fixtures with electronic ballasts. It wanted to add occupancy-sensor controls to all of its office and warehouse space. Assume that the basic reference case was the operation characteristics immediately before the occupancy sensor project, and that this project had no other appreciable effects. The steps necessary to complete the estimation of energy savings were as follows:

Step 1. Monitor the operating hours for the reference case and the project, using run-time meters on a representative number of fixtures. Assume that the store found the average reference case hours to be 4,865 hours per year, but the average hours with the occupancy sensor control project were 3,406 hours per year.

Step 2. Measure kW using spot meters. The required power was the same for both the reference case and the project: 10.9 kW when all the lights were on.

Step 3. Calculate the energy savings using the following equation:

$$\text{Energy Savings} = P \bullet \left[H_{bref} - H_{proj}\right]$$

where P = power requirements, kW
H_{bref} = annual operating hours in the basic reference case
H_{proj} = annual operating hours with the occupancy sensor project.

$$\begin{aligned}\text{Energy Savings} &= 10.9 \text{ kW} \bullet [4{,}865 \text{ hours} - 3{,}406 \text{ hours}] \\ &= 15{,}903 \text{ kWh}\end{aligned}$$

Step 4. Calculate the reduction in greenhouse gas emissions (see Section 2.8).

Example 2.8 - End-Use Meters for Occupancy Sensor Controls

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A more expensive approach to estimating the energy savings is to use short-term, end-use metering for both the reference case and the project. These results need to be extrapolated to an annual representation, and the energy savings in kWh per year is calculated using the equation from Section 2.6.1:

$$\text{Energy Savings} = \left[E_{bref} - E_{proj}\right]$$

Again, the reduction in greenhouse gas emissions would be computed as discussed in Section 2.8.

2.6.4 Variable Load

The previous three sections discussed projects only involving constant loads. Another pattern of loading, called variable (or partial) loading, occurs when a device has a continuously changing load placed on it. Part-load curves indicate what fraction of input energy a piece of equipment must use to generate the desired output levels. The full-load condition is also sometimes referred to as the "design condition"—the equipment has generally been designed to operate most efficiently at the full-load condition. The part-load ratio may also be expressed in terms of the input and output units for the equipment (for example, chiller manufacturers may provide a part-load curve that provides kW of energy required per ton of cooling at various loading conditions).

Some typical applications of variable-load devices include chillers, variable-speed drives, variable-frequency motors, and default dimmers.

Example 2.9 demonstrates one method—part-load curves—that is effective for this type of application. Example 2.10 illustrates the replacement of a single-stage absorption chiller with an electric chiller.

Example 2.9 - Part-Load Curves for Fan Motor Upgrades

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A restaurant upgraded its ventilation system from a constant-speed fan motor in conjunction with inlet vanes to one using a variable-speed drive that varied the load on the fan motor with the varying amount of ventilation required. The analysis used a basic reference case, based on fan operating characteristics immediately prior to the project's implementation.

Assume that the project had no significant secondary effects. Also assume that the fan, both before and after project implementation, was rated at 3 thousand cubic feet per minute (MCFM). The estimation was completed as follows:

Step 1. Perform short-term monitoring with a data logger to measure the air volume (CFM) that the fan is moving, along with time stamp information. Remember to monitor performance long enough to ensure that the recorded data are typical of the fan's operation during the year.

Step 2. For each hour, calculate the part-load factor of the fan as the CFM for that hour divided by the full CFM capacity of the fan.

Step 3. Decide how many bins are required to accurately represent the true operational conditions of the fan. In this example, 10 bins were used.

Step 4. For each bin, aggregate the power requirements for the reference case (in kW per MCFM) from the monitoring data and determine the power requirements for the project from manufacturer's data, as presented in the following table.

Part-Load Curves

Part-Load Factor % Full CFM Capacity	Operating Hours	Reference Case kW/MCFM	Project kW/MCFM
10	20	0.9	0.6
20	350	0.8	0.5
30	700	0.7	0.4
40	800	0.6	0.3
50	900	0.5	0.2
60	1000	0.4	0.2
70	1250	0.3	0.1
80	1100	0.2	0.05
90	900	0.3	0.1
100	800	0.4	0.2

Step 5. Calculate the energy savings as the rated capacity of the fan multiplied by the sum of the products of the part-load factor and the operating hours and the change in kW/MCFM between the pre-and post-conditions in each bin. In equation form, this is shown as follows:

$$\text{Energy Savings} = RC \bullet \sum_i \left[H_i \bullet PLF_i \cdot \left(\frac{kW}{MCFM_{bref}} - \frac{kW}{MCFM_{proj}} \right) \right]$$

$$= (3\ \text{MCFM}) \bullet \left(1{,}065\ \frac{kWh}{MCFM} \right)$$

$$= 3{,}195\ \text{kWh}$$

Example 2.9 - (cont'd)

where RC = rated capacity of the fan

H_i = hours in bin i

PLF_i = part-load factor in bin i

$(kW/MCFM)_{bref}$ = measured kW per thousands of CFM before the installation of the activity

$(kW/MCFM)_{proj}$ = measured kW per thousands of CFM after the activity has been implemented.

The advantage of this method is that it can be used to predict an accurate energy savings estimate. Once the energy savings are calculated, the emissions reductions can be computed as discussed in Section 2.8.

Example 2.10 - Chiller Replacement

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A commercial building located in Washington, DC, planned to install a new chiller. The existing equipment was a single-stage absorption chiller (22,000 Btu/ton-hr heat rate), fueled by natural gas, which could have continued to function at the current service level for many more years. The building manager explored two types of chillers, a two-stage absorption chiller and an electric chiller. Using the management company's established method, she calculated the payback period and chose the electric chiller. Since her management company had announced an intention to report under the EPAct 1605(b) voluntary reporting program, she analyzed the chiller replacement as an emissions reduction project.

She established the reference case as emissions from the old chiller (a basic reference case). Her assistant, who performed the estimations, suggested that the performance of the two-stage absorption chiller, which met current efficiency guidelines, should be used as the reference case. However, the basic reference case better showed actual emissions. (Had the company installed a new chiller where none had existed, the two-stage absorption-chiller might well have been a credible modified reference case.) Cooling load was expected to remain at 150,000 ton-hours per year.

To calculate how each equipment choice will affect the amount of emissions produced, the manager first determined the amount of energy (or fuel) used by each chiller and then applied emission factors.

Reference Case: Single-Stage Absorption Chiller (natural gas-fired)

The building manager calculated the annual fuel input:

$$22{,}000 \text{ Btu/ton-hr} \bullet 150{,}000 \text{ ton-hr/yr} = 3.3\text{x}10^9 \text{ Btu/yr}$$

Using this figure and the emissions factor for natural gas from Appendix B of this volume (see the discussion in Section 2.8), she estimated annual fuel emissions:

$$3.3\text{x}10^9 \text{ Btu/yr} \bullet 52.8\text{x}10^6 \text{ MTCO}_2/10^{15} \text{ Btu} = 174.2 \text{ MTCO}_2$$

She then determined annual auxiliary (electricity) energy consumption under the reference case:

$$0.3 \text{ kW/ton} \bullet 150{,}000 \text{ ton-hr/yr} = 45{,}000 \text{ kWh} = 45 \text{ MWh}$$

Using the emissions factor for the District of Columbia from Appendix C of this volume, she estimated the annual auxiliary emissions:

$$45 \text{ MWh} \bullet 1.324 \text{ STCO}_2/\text{MWh} = 59.6 \text{ STCO}_2 = 54.2 \text{ MTCO}_2$$

To estimate total emissions for the reference case, she added fuel-based emissions and auxiliary emissions:

$$174.2 \text{ MTCO}_2 + 54.2 \text{ MTCO}_2 = 228.4 \text{ MTCO}_2$$

Project Case: Electric Chiller

The building manager calculated annual energy consumption for the new electric chiller:

$$0.7 \text{ kW/ton} \bullet 150{,}000 \text{ ton-hr/yr} = 105{,}000 \text{ kWh} = 105 \text{ MWh/yr}$$

She estimated total emissions, using the same electricity emissions factor as she used in the reference case:

$$105 \text{ MWh} \bullet 1.324 \text{ STCO}_2/\text{MWh} = 139.0 \text{ STCO}_2 = 126.4 \text{ MTCO}_2$$

Emissions Reductions:

$$228.4 \text{ MTCO}_2 - 126.4 \text{ MTCO}_2 = 102 \text{ MTCO}_2$$

2.6.5 Combination/Interactive Loads

Combination loads occur when a group of energy-conservation activities has been applied at a site. It is often difficult to identify the discrete effects of each individual activity. In this case, you may more easily examine the interactive effect from all of the activities as a single energy-savings estimate. Conservation activities such as high-efficiency lighting, high-efficiency HVAC, and building-shell measures (for example, ceiling and wall insulation) commonly combine to form interactive loads. Rather than attempting to define the effects of these activities narrowly at the device level, it may simplify analysis to define the effects at the building level. This method can also be used to observe the true savings resulting from a large energy conservation activity.

Three methods that work well for examining the effects of large energy-conservation activities are (1) site-specific billing history analysis, (2) whole-building load-research data analysis, and (3) building simulation.

Site-specific billing analysis

Site-specific billing analysis is particularly appropriate when you are using a basic reference case. The advantage of this approach is that billing history data are readily available (from kept records or from the utility) and can be quickly examined for savings estimates. It is not as readily applicable, however, for use with a modified reference case, such as when you want to account for changes in building occupancy or energy-use patterns. Example 2.11 illustrates the use of this estimating method.

Example 2.11 - Site-Specific Billing History Analysis for Lighting Conservation

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a retail store's lighting energy was 60 percent of its annual energy consumption. The expected energy savings from the lighting activity was almost 14 percent of the store's annual energy use, which implied that the impact of the activity should have been easily observed in the changes in billing history. Keep in mind that billing history in institutional buildings has inherent variability in the range of 8 percent to 14 percent from year to year owing to weather, schedule changes, and other effects. Therefore, the expected energy savings should be at least 15-20 percent of the annual bills (DOE/BPA 1991).

Assume that the analysis defined a basic reference case drawn from the year immediately before the project's implementation and that the project had no significant effects other than saving energy. The estimation of energy savings proceeds as follows:

Step 1. Assemble one year (or more) of billing history data (typically available from the electricity supplier) before the conservation activity for estimating the reference case, and one year of data after the project's implementation. The following table presents the monthly billing history for the site before and after the lighting activity.

Example 2.11 - (cont'd)

Billing History Analysis

Month	Reference Case Energy Use (kWh)	Project Energy Use (kWh)
January	16,456	14,653
February	16,544	14,698
March	14,509	13,070
April	19,947	15,573
May	18,012	15,904
June	20,357	16,428
July	16,174	13,909
August	17,964	13,781
September	15,131	12,820
October	16,837	12,949
November	15,764	13,655
December	17,979	14,383
Annual Totals	205,674	171,823

Step 2. Calculate the energy savings using the equation from Section 2.6.1:

$$\text{Energy Savings} = [E_{bref} - E_{proj}]$$
$$= 205{,}674 \text{ kWh} - 171{,}823 \text{ kWh}$$
$$= 33{,}851 \text{ kWh}$$

Step 3. Calculate the reduction in emissions (see Section 2.8).

Whole-building, load-research data analysis

Whole-building, load-research data are a record of historical demand data at a facility, generally recorded in 15-minute increments. You can readily aggregate the data into monthly energy usage for analysis—resulting in data similar to monthly billing histories. The primary advantage of load-research data is that in addition to energy savings, demand savings can also be observed. The main disadvantage is that the data can be expensive to collect if you must purchase the meter, although some utilities will install meters free of charge or at a low cost.

Building simulation

Building simulation provides an effective tool for examining interactive effects and energy-conservation activities that are difficult to estimate using other techniques. The disadvantages of building simulations are that they tend to be data intensive and difficult to operate, and interpreting the results can be complex.

2.6.6 Demand-Side Management Program Analysis

In general, the previous analytical techniques have tended to be most applicable to the analysis of energy savings for a device, group of devices, or a single site (residence, facility, etc.). This is not how electric and natural gas utilities commonly report energy savings resulting from DSM programs. The calculations of energy savings can be a complex process with uncertainties introduced by economic and behavioral effects, such as free riders (entities who would have implemented DSM activities without the utility program, but take advantage of the utility rebate because of its ready availability) and, to a lesser degree, free drivers (entities who have become aware of DSM technologies through the utility program and subsequently implemented energy-conservation activities). Fortunately, a growing base of experience with DSM program management and evaluation has yielded increasingly sophisticated measurement techniques that can provide relatively solid estimates of program performance. Utilities are encouraged to use the methodologies already in place, for example, to estimate energy savings as part of their reports to public utility commissions.

Delineating specific estimating methods is beyond the scope of this supporting document. Generally, several approaches may be used to estimate net energy savings, including billing history analysis, econometric models, end-use metering, and, to a lesser degree, building simulation. For DSM programs using a basic reference case, estimation of energy savings is generally based upon pre-and post-measurement of energy savings for a sample of program participants. The sample of program participants needs to be statistically representative of all the participants in the program.

DSM programs may include collection and disposal of refrigerators and cooling equipment. If you report these activities, you may also report (as applicable) capture of chlorofluorocarbons associated with the activities. You will find guidance in the supporting document for the industrial sector.

2.7 Estimating Energy Savings for Projects with a Modified Reference Case

Most device-level and building-level analyses use a basic reference case, either because energy-use patterns from the past are not expected to change or because evaluating the change would be very difficult. If you use a modified reference case (for example, to account for projected growth), your analysis needs to reflect elements, such as DSM programs, that will affect the modified case. You may use any estimation method appropriate to your circumstances, for example, the methods you use in the integrated resource planning (IRP) process.

However, for DSM programs you may be able to develop and evaluate modified reference cases (perhaps with methods you already have in place) using the following: (1) pre- and post-measurement of energy savings from both a sample of program participants and a control group or (2) post-measured savings for a sample of participants compared to the savings from a control group.

The advantages of control group analysis are that several economic and behavioral effects can be observed, including free rider and free driver effects. In addition, the confidentiality of program participants is maintained, since no energy savings are reported for individual activities. The disadvantages are that control group analysis needs to be performed long after the energy-conservation activities have been implemented (typically one year) to capture the annual energy savings. Also, the reasons or motivations underlying the achieved energy savings may not be captured or recorded.

In some cases, a modified reference case can be used at a lower level of aggregation, even at the device level. For example, post-retrofit monitoring is ideally suited to capture changes in energy demand due to changes in hours of operations (see Example 2.9).

While thus document does not provide specific procedures for developing modified reference cases under these conditions, generally you must be sure that you are comparing your project to a credible estimate of the energy that would have been consumed if the project had not been implemented.

2.8 Estimating Emissions Reductions from Energy Savings

The previous sections have discussed how to estimate energy savings from conservation projects. But the purpose of the voluntary reporting program is to record greenhouse gas emissions and emissions reductions, not energy savings. Therefore, you must calculate the net emissions reductions resulting from energy-efficiency activities affecting both direct (fossil) and indirect (electric) fuel use, fuel-switching activities, cogeneration, and any other activities that save energy.

If you monitor greenhouse gas emissions, you may simply report the difference in measured emissions between your reference and project cases. If instead you wish to estimate emissions reductions from fuel-use or electricity-use data, you may use default emissions factors, as explained in this section, or use the more complex approaches described in the supporting document for the electricity supply sector, particularly Section 1.7.

2.8.1 Direct Monitoring of Nonelectric Activities

For nonelectric energy-conservation activities, you may directly monitor the change in greenhouse gas emissions resulting from a single activity or group of activities. You may define reference and project cases based on the data available to you. For example, if you monitor emissions for your entire operation, you may define both reference and project cases at the entity level.

2.8.2 Applying Emissions Factors to Energy Savings Data

If you do not monitor emissions directly, either because you do not have the capacity to do so or your project affects emissions indirectly (for example, electricity conservation), you can use emissions factors to calculate the emissions associated with your reference case and project case. Emissions factors translate consumption of energy into greenhouse gas emissions levels.

You can use the default emissions factors provided in Appendix B to derive carbon dioxide emissions associated with the use of various fossil fuels. Appendix C provides default emissions factors for electricity consumption on a state-by-state basis. Alternatively, you may be able to obtain data from your utility or nonutility electricity source. You may also choose to derive your own electricity emissions factors as described in Section 1.7.2 of the support document for the electricity supply sector.

Whether you use default emissions factors or factors you have derived yourself, you can use them in the following equation to calculate the total emissions reductions associated with your project:

$$\textbf{Emissions Reductions}_i = \sum_j \textbf{Energy Savings}_j \bullet \textbf{Emission Factors}_{ij}$$

where Emissions Reductions_i = the annual decrease in emissions of greenhouse gas i that results from the energy-conservation activity

Energy Savings_j = the annual reduction in use of fuel j resulting from the energy-conservation activity (note that increased use of a fuel is indicated by a negative number)

Emissions Factor_{ij} = emissions factor for greenhouse gas i associated with fuel j.

The following example illustrates the use of the energy conversion factors for electricity to derive the emissions reductions attributable to an energy conservation project.

Example 2.12 - Calculated Emissions Reductions

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a commercial facility located in Delaware has retrofitted its lighting, as described in Example 2.2. The steps necessary to complete the savings analysis were as follows:

Step 1. Calculate the energy savings resulting from the activity. Annual energy savings were previously calculated as 85,500 kWh per year.

Step 2. Derive or select the appropriate emissions factor for converting electricity reductions to emissions reductions. Default emissions factors for Delaware were extracted from Appendix C to this volume:

Default Emissions Factors

Greenhouse Gases	Emissions Factors (lbs/kWh)
Carbon Dioxide	1855
Nitrous Oxide	0.2161

Step 3. Calculate the emissions reductions for each of the greenhouse gases as follows:

The annual carbon dioxide emissions reductions were calculated using

$$\begin{aligned} CO_2 \text{ Emissions Reductions} &= \text{(Electricity Savings)} \bullet \text{(Emissions Factor)} \\ &= 85.5 \text{ MWh} \bullet 1855 \text{ lb } CO_2/\text{MWh} \\ &= 159 \text{x} 10^3 \text{ lb } CO_2 \end{aligned}$$

The annual nitrous oxide emissions reductions were calculated thus:

$$\begin{aligned} N_2O \text{ Emissions Reductions} &= \text{(Electricity Savings)} \bullet \text{(Emissions Factor)} \\ &= 85.5 \text{ MWh} \bullet 0.2161 \text{ lb } N_2O/\text{MWh} \\ &= 18.47 \text{ lb } N_2O \end{aligned}$$

2.9 Existing Reporting Programs

In several cases, reporters may have participated in state or Federal reporting programs that record energy-conservation activities and potentially even some reductions in either acid rain pollutants or greenhouse gas emissions. Electric utilities, investor-owned public utilities, Federal power-marketing administrations, and the Tennessee Valley Authority are required to report financial, operating, fuel-use, and DSM information periodically. Some specific examples of standardized reporting programs that contain energy-conservation information are the DOE Energy Information Administration Form EIA-861, *Annual Electric Utility Report Schedule V - Demand-Side Management Information,* and EPA's Green Lights program. Additional nonstandard sources of energy-saving accomplishments by public utilities may be found in the form of submissions to their respective public utility commissions.

2.9.1 EIA Form 861

The Federal Energy Administration Act of 1974 requires U.S. utilities to complete and return Form EIA-861 to the EIA. The form requests data on the incremental and annual energy effects (MWh) and potential and actual peak reduction (kW) for the following DSM categories: energy efficiency, interruptible load, other load management, other DSM programs, direct load control, and load building. The DSM program achievements are reported by customer class (residential, commercial, industrial and other), and there is a check box at the end of the form to indicate the end uses (heating systems, lighting, etc.).

Incremental and annual effects

"Incremental effects" are defined as the changes in energy use caused in the reporting year by new participants in existing DSM programs and all participants in new DSM programs. Effects are annualized "to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the reporting year." "Annual effects" are defined as the total changes in energy use and peak load caused in the reporting year by all participants in all the utility's DSM programs.

Providing data on incremental effects, as defined in Form EIA-861, would not reveal actual savings if any of the savings are annualized. For example, the energy savings attributed to a utility-influenced purchase of an efficient refrigerator in September would be calculated to the entire year, as opposed to the four months of actual use. If the savings were not annualized, the incremental effects data would provide a good approximation of the actual savings for the reporting year and would partially meet the needs of this voluntary reporting program. Then, as described in Section 2.8, the energy savings could be translated into associated impacts on greenhouse gas emissions.

Energy effects and peak reduction

Although Schedule V requests information on both energy effects (MWh) and peak reduction (kW), only the energy effects data (Form EIA-861, Schedule V, page 5) are applicable to reporting under the EPAct Section 1605(b) reporting program.

EPA's Conservation Verification Protocols

The main goal of this protocol is to credit electrical utilities for SO_2 emission reductions as a result of conservation programs. As a result, this protocol is fairly flexible in what types of calculations or measurements are performed. If estimates are based on end-use metering, the utilities must use a comparison (or control) group and the reported energy savings must have a statistical confidence of at least 75 percent.

If engineering analyses are used instead of monitoring techniques, the savings results are discounted to reflect the lower confidence and accuracy of the results. The protocol suggests that engineering calculations only be used in the following conditions:

- Measurement cost would exceed 10 percent of the program cost.
- Program-wide energy savings are small ($<$ 5000 MWh per year).
- Energy savings are less than 5 percent of the smallest isolatable circuit.
- Energy savings are less than 5 percent of the total household electricity use.

The Conservation Verification Protocols (CVPs) also allow engineering estimates for seven specific categories:

- constant load motors
- exit signs
- amorphous metal transformers
- commercial lighting
- new refrigerators
- street lights
- water heater insulation.

The discounting of estimates in these categories is less severe than for other areas, to reflect the higher quality of data available.

2.9.2 EPA's Green Lights Program

The Green Lights (EPA 1992) program is a cooperative program with public and private organizations to replace inefficient lighting with new, energy-efficient lighting technologies. The program provides participants with a one-page form on which to report their lighting upgrade activities. The form includes general facility information, total facility floor space, and upgraded floor space; fixture type, size, quantity, and wattage used before and after the upgrade; operating hours; electrical demand and energy savings; the percent of energy savings (relative to the base usage); the cost savings in dollars; and the reduction in emissions of CO_2, SO_x, and NO_x.

Although no methods of estimation are indicated on the form, a description of who performed the analysis (in-house personnel, energy consulting firm, etc.) is requested. As with other reporting programs, the portion that is needed for this voluntary reporting program is the annual energy savings from the energy-conservation activity. These figures can be readily obtained from the Green Lights reporting form.

2.9.3 Public Utility Commission Filings

In addition to completing EIA-861 forms, investor-owned utilities and some public utilities provide state public utility commissions with information on the effectiveness of DSM programs. This information is typically submitted as part of the utility's general rate case, which occurs every two to three years. Utilities can also provide annual information to include data on program participation rates, program costs, the duration of the measure, and free riders. State energy offices and energy service companies (ESCOs) use a wide variety of verification systems, though these may be geared toward shareholder value and cost effectiveness. Utilities use data on kWh and kW savings to evaluate program savings and cost-effectiveness.

Energy savings in buildings also reduce electric utility transmission and distribution (T&D) and generator losses. These losses have not always been explicitly considered in past public utility commission filings but are certainly relevant and could be included in submissions under this voluntary reporting program.

As noted under the EIA-861 report forms, only kWh savings data are required to estimate emissions reductions. In reporting estimated savings, you must note the method(s) you used to develop the estimates.

The natural gas industry is regulated by the Federal Energy Regulatory Commission and in some states local distribution companies are regulated by public utility commissions. In states, such as Georgia and California, where the Public Service Commission regulates natural gas, gas utilities are required to submit integrated resource plans that delineate DSM program activities. The same information reported to the public utility commissions may assist in computing greenhouse gas reductions for reporting under the EPAct Section 1605(b).

2.10 References

U.S. Environmental Protection Agency (EPA). March 1993. *Conservation Verification.* EPA Form-7610-11 (3-93). Washington, DC.

U.S. Environmental Protection Agency (EPA). March 1993. *Conservation Verification Protocols, A Guidance Document for Electric Utilities Affected by the Acid Rain Program of the Clean Air Amendments of 1990.* EPA 430\B-92-002. Washington, DC.

U.S. Environmental Protection Agency (EPA). April 1993. *The Users Guide to the Conservation Verification Protocol.* EPA 430-B-93-002. Washington, DC.

U.S. Environmental Protection Agency (EPA). February 1992. *Green Lights Program: The First Year*, EPA/400/1-92/003, Washington, DC.

U.S. Department of Energy, Energy Information Administration (EIA), Office of Energy Markets and End Use. May 1991. *Commercial Buildings Characteristics 1989.* DOE/EIA-0246(89), U.S. Government Printing Office, Washington, DC.

Appendix 2.A

Energy Conservation Measures

Energy Conservation Measures

Space Heating
- Improved Heating Efficiency
- Hot Thermal Storage

Air Conditioning
- Improved Cooling Efficiency
- Cool Thermal Storage

Ventilation
- Improved Motor Efficiency
- Multi-Speed or Variable-Speed Motor
- Duct Sealing & Balancing
- Variable Air Volume

Water Heating
- High-Efficiency Water Heaters
- Insulation Blankets
- Flow Restrictors
- Heat Pump Water Heater

Refrigeration
- High-Efficiency Refrigeration Cases
- Defrost Control
- Variable-Speed Compressors
- Multi-Stage Compressors

Lighting
- Compact Fluorescent
- Electronic Ballasts
- High-Efficiency Magnetic Ballasts
- Reflector Systems
- Efficient Fluorescent Lamps
- Lighting Controls
- Exit Signs
- Occupancy Sensors
- High-Intensity Discharge Lamps
- Daylight Dimmers
- Daylight Switches

Building Envelope
- Insulation
- Weatherization
- Insulating Glass
- Low Emissivity Glass

Controls
- Energy Management System (EMS)
- Direct Load Control
- Distributed Load Control

Appliances
- High-Efficiency Appliances

Other
- Cogeneration
- Fuel Switching
- Renewable Energy Source
- High-Efficiency Motors
- Variable-Speed Motors
- Efficient Distribution Transformers
- High-Efficiency Office Equipment and Computers

Appendix 2.B

Energy Estimation Techniques

Energy Estimation Techniques

Engineering analysis. Engineering analyses are used to develop estimates of energy savings based on technical information from manufacturers in conjunction with assumed operating characteristics of the equipment.

"Stipulated measures" are defined as constant load applications that operate continuously, have known operating hours, or are new appliances (such as refrigerators) sold with Energy Guide labels indicating average energy savings.

The advantage of engineering estimates is they are relatively quick and inexpensive to calculate. The primary disadvantage is that the data used in the calculations rely on assumptions that may vary in their level of accuracy.

Building simulation models. Building simulation models are really a collection of engineering equations. They can be used to develop end-use load shapes for utility forecasting and demand-side management planning, to analyze trade-offs for standards development, and to estimate energy savings from various energy-conservation activities.

One advantage of simulation models is that they take into account such factors as weather data and interactions between the HVAC system and other end uses. A primary disadvantage is that they are very time consuming and usually require specialized technical expertise, making them costly in the long run.

Analysis of past utility bills. This technique can be used to develop a facility's baseline energy use. Energy savings are determined by comparing the metered energy use in the current year to the baseline year. For space heating and cooling, energy use is normalized for weather changes. In addition, energy use figures may be adjusted to account for changes in site operations.

The primary requirement for using past utility bills as a baseline is that the energy savings are larger than the normal bill variations. The BPA Guidelines (Harding et al. 1992) state that the annual energy use of institutional buildings may vary from 8 to 14 percent. Therefore, the energy savings adjustment should be at least 15 to 20 percent of the baseline year usage to differentiate actual savings from anomalies.

The annual savings are estimated as follows:

$$\textbf{Energy Savings} = \left[E_{bref} - E_{proj}\right]$$

where Energy Savings = annual energy savings resulting from the activity, in kWh

E_{bref} = typical annual energy use of the activity before installation (typically this is averaged over several years)

E_{proj} = billing history for the year following the activity implementation adjusted for weather and operational changes.

The advantage of analyzing past utility bills is that comparing the data is inexpensive, and the results are easy to understand and communicate. The disadvantages include limited applicability because of the need for stable building operations and the need to normalize for weather and changes in building use. Appropriate applications for this technique are (1) for large institutional complexes (such as the U.S. Department of Defense currently is doing) and (2) where the energy savings are at least 25 percent of the annual billing history for a given meter or site.

Statistical techniques are often used to evaluate and verify energy savings from efficiency programs. In all cases, participant samples of significant size are required for validity. Normally, billing histories of participants are used in a pre/post or sample/control experimental framework. Weather, building size, and econometric normalization will be applied to separate the net savings from the noise of naturally occurring variation. Variations of this technique are widely used to evaluate utility demand-side management programs.

Spot metering. Spot metering is a useful tool for estimating energy savings when the efficiency of the equipment is enhanced, but the operating hours remain fixed, such as with an exit sign replacement project. Spot metering of the connected load before and after the activity quantifies this change in efficiency with a high degree of accuracy. For activities where the hours of operation are variable, the actual operating (run-time) hours of the activity should be measured before and after the installation using a run-time meter.

The annual savings are estimated as follows:

$$\textbf{Energy Savings} = \left(P_{bref} - P_{proj}\right) \bullet \textbf{Hours}$$

where Energy Savings = annual energy savings resulting from the activity

P_{bref} = connected load before the activity is installed
P_{proj} = connected load after the activity is implemented
Hours = the number of hours the device runs during the year.

The advantage of the spot metering is that it is simple and easy to apply. This method is more accurate than using engineering calculations, since the parameters are measured instead of being assumed. The advantage over the billing history approach is that it can be used when energy savings are a small (<15 percent) portion of the annual energy use at a site or a meter. However, the scope of its applicability may be limited to those projects where operating hours are the same before and after treatment.

End-use metering. End-use metering is a useful tool for estimating savings that are not a function of fixed hours. Using variable-speed drives in place of variable inlet vanes, for example, reduces fan-motor loading and energy use. Extended metering is required before and after the retrofit to characterize the performance of the equipment under a variety of load conditions.

The annual savings are estimated as follows:

$$\textbf{Energy Savings} = \left[E_{bref} - E_{proj}\right]$$

where Energy Savings = average energy savings per unit (that is, kWh per day) resulting from the activity

E_{bref} = average energy use per unit before the activity was installed
E_{proj} = average energy use per unit after the activity is implemented.

The advantage of end-use metering is that it provides a greater degree of accuracy than engineering estimates or spot metering. In addition, the meter can calculate the energy change on an individual piece of equipment in isolation from the other end-use loads (as opposed to billing history, which captures the effect at the building or meter level). End-use metering requires specialized equipment and an equipment technician, and is typically more costly than any of the previous four methods.

Metering of load research data. Another type of data that may be available at the meter or building level is load research data (LRD). The difference between this type of metering and end-use metering is the level at which the activity is metered. End-use meters generally are used to meter a single circuit or piece of equipment, while LRD meters the building or account total. In general, utilities are required to collect LRD on a statistically valid sample of buildings for their territories.

Since the LRD meter is at the building level, the requirements are similar to the billing history analysis—that is, the energy savings need to be larger than normal variations in the load research data.

In its raw form, the LRD represent electrical demand (kW), typically in 15-minute or hourly increments. However, it is fairly straightforward to collapse this into electrical energy (kWh). Therefore, both energy and demand savings could be calculated for the activity if desired.

The annual savings are estimated as follows:

$$\textbf{Energy Savings} = \left[E_{bref} - E_{proj}\right]$$

$$\textbf{Demand Savings} = \left[P_{bref} - P_{proj}\right]$$

where Energy Savings = annual energy savings resulting from the activity
Demand Savings = reduction in load resulting from the activity
bref = typical characterization of the activity before installation (usually this is averaged over several years)
proj = the characterizations after the activity has been implemented.

The advantage of LRD analysis is that the data may already be available through the electric utility. The disadvantages include limited applicability due to the need for stable building operations, the need to normalize for weather and changes in building use, and increased computational requirements. The LRD analysis may be applied in the same circumstances as billing history analysis.

Flow meters. If an energy-conservation activity involves a nonelectric fuel source, data from flow meters may be used. When installed in pipes, these meters measure the energy used by the device. In addition, flow meters could be installed at the appliance, end-use level, similar to electric end-use meters.

Manufacturers' estimates. Several appliance manufacturers (refrigerators, water heaters, clothes washers and dryers, etc.) provide estimates of energy savings in the form of Energy Guide labels. These labels indicate the annual energy cost (in dollars) for using the appliance in a typical family or under typical conditions. Besides providing a simple, standardized method for reporting savings, these labels may be an excellent source of information for residential homeowners to use if they are assuming reporting responsibilities under this program.

Statistical analysis. Statistical analysis can be used in several ways, including conditional demand models, econometric models, and weather normalization. Weather normalization is used to separate out the heating, ventilation, and air conditioning (HVAC) energy from the total energy use in the facility; this could be a requirement if billing history or load research data are used to examine the energy savings from an HVAC activity.

Hybrid techniques. Hybrid techniques combine one or more of the above methods to create an even stronger analytical tool. For example, spot metering could be combined with engineering analysis. The hours of operation before and after are still estimated, but the before-and-after efficiency is now measured, as opposed to being estimated. Statistically adjusted engineering analysis is used by many utilities. The down side of hybrid techniques is that while they can provide more accurate results, they typically increase the complexity and expense.

Fuel-switching analysis. Fuel-switching savings can be estimated and verified using all of the techniques previously discussed. However, accounting for the shifting of energy use and related changes in emissions associated with fuel-switching activities creates a potentially more complex reporting situation.

For example, a natural gas utility wishing to increase sales provides a rebate to its commercial customers who replace electric-resistance space and water-heating equipment with high-efficiency natural gas units. The commercial building owner participating in the program would need to report a reduction in electricity use and an increase in natural gas use. Is there a net reduction in greenhouse gas emissions? The solution involves comparing the indirect emissions reductions from reduced electricity use with the new direct emissions from increased on-site fossil fuel use.

Before switching fuels, which typically involves major renovations and a large capital investment, a reporting entity will have performed a detailed engineering (and usually a life-cycle cost) analysis of the alternative fuel. The reporting entity can use this engineering analysis to estimate first-year fuel savings and also to firm up post-hoc savings typically calculated through utility bill analysis at the end of the year.

The original engineering analysis may include real-time monitoring of equipment performance and energy use (calibrated with hourly or daily temperature/weather data and projected over the entire year). Building-simulation programs and other computer-based tools for estimating and characterizing the building's energy consumption are also commonly used to provide data on the fuel savings associated with the fuel switching. All of these approaches for determining overall energy use and emissions are acceptable under the voluntary reporting program.

Renewable-energy analysis. Renewable-energy systems can be estimated and verified using all of the techniques previously discussed. For example, utility bill monitoring alone can provide accurate savings estimates for solar thermal projects where the original fossil fuel use was dedicated to the end-use requirement met by the solar system.

Reference

Harding, S., F. Gordan, and M. Kennedy. 1992. *Site Specific Verification Guidelines*. Bonneville Power Administration, Portland, OR.

Industrial Sector

Part 3 of 6 Supporting Documents

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Examples

Figures

Tables

3.0 Industrial Sector

This document supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act (EPAct) of 1992. The General Guidelines provide the rationale for the voluntary reporting program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this supporting document, you should read the General Guidelines. Then read this document, which relates the general guidance to the issues, methods, and data specific to the industrial sector. Other supporting documents address the electricity supply sector, the residential and commercial buildings sector, the transportation sector, the forestry sector, and the agricultural sector.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon sequestration projects. When you understand the approaches taken by the voluntary reporting program, you will have the background needed to complete the reporting forms.

The General Guidelines and supporting documents address four major greenhouse gases: carbon dioxide, methane, nitrous oxide, and halogenated substances. Although other radiatively enhancing gases are not generally discussed, you will be able to report nitrogen oxides (NO_x), nonmethane volatile organic compounds (NMVOCs), and carbon monoxide (CO) after the second reporting cycle (that is, after 1996).

The Department of Energy (DOE) has designed this voluntary reporting program to be flexible and easy to use. For example, you are encouraged to use the same fuel consumption or energy savings data that you may already have compiled for existing programs or for your own internal tracking. In addition, you may use the default emissions factors and stipulated factors that this document provides for some types of projects to convert your existing data directly into estimated emissions reductions. The intent of the default emissions and stipulated factors is to simplify the reporting process, not to discourage you from developing your own emissions estimates.

Whether you report for your whole organization, only for one project, or at some level in between, you will find guidance and overall approaches that will help you in analyzing your projects and developing your reports. If you need reporting forms, contact the Energy Information Administration (EIA) of DOE, 1000 Independence Avenue, SW, Washington, DC 20585.

3.1 Industry: Overview

This supporting document provides technical guidance on reporting both industrial greenhouse gas emissions and the effects of projects you undertake to reduce those emissions. Guidance is provided for reporting activities that have reduced greenhouse gas emissions at an industrial site, by reducing on-site fossil fuel consumption, changing the composition of fossil fuel use, or reducing direct emissions from industrial processes; and at off-site locations, by reducing electricity purchases resulting in lower fossil fuel use at electric power generating plants.

The industrial sector is diverse, encompassing extraction and production of basic materials, conversion of materials into intermediate products, and manufacture of final goods. These activities give rise to emissions of various greenhouse gases, as illustrated in Table 3.1.

The industrial activities that produce greenhouse gas emissions may be classified into two groups: energy-related emissions (for example, from fossil energy consumption) and other emissions from industrial process operations (for example, from coal mining or cement production). This supporting document provides guidance for reporting emissions and emissions reductions associated with both groups of activities. This supporting document provides technical assistance and illustrative examples to support each of the steps involved in estimating emissions and emissions reductions for the industrial sector. Note that each example is provided for illustrative purposes only; other appropriate ways of evaluating these hypothetical projects may exist.

3.1.1 Reporting Entities

A typical industrial reporter could be a corporation or company, a subsidiary, or a single plant or establishment. If you have multiple subsidiaries or establishments, you may wish to combine some or all of them into a single report, or you may wish to report separately for each subsidiary or establishment.

Table 3.1. Industrial Sources of Greenhouse Gases

Greenhouse Gas	Major Industrial Sources
Carbon Dioxide (CO_2)	Fossil fuel combustion Cement production
Methane (CH_4)	Coal mining Oil and natural gas system operation Landfill operation Stationary combustion
Nitrous Oxide (N_2O)	Adipic acid production Stationary combustion
Halogenated substances (CFCs, HCFCs, PFCs, etc.)	Deliberate manufacture and use Use or production in industrial processes

3.1.2 *Sector-Specific Issues*

The industrial sector is complex and diverse. The number and type of potential emissions-reducing activities in industry is large, and analyzing emissions-reduction projects may involve a number of calculations. For example, you may need to determine the effects of projects on the use of various fuels and electricity, on energy related and non-energy related emissions, and on emissions in other sectors in addition to the industrial sector (for example, a project that reduces emissions from an industrial process may also change within-plant or between-plant transportation requirements).

In spite of this complexity, you may find it worthwhile to collect information on the effects of your projects. Many organizations have found that conducting energy audits and analyzing the costs and energy savings associated with the audit findings identifies many cost-effective ways to save energy. If you have such information, you may find reporting under the EPAct 1605(b) program to be especially straightforward. In addition, various surveys collect data on energy use in manufacturing. If you are a survey participant, you may be able to use the data you gather for these surveys as a basis for developing your EPAct Section 1605(b) report.

You may also be able to take advantage of other existing information. For example, under the Motor Challenge program, the Department of Energy is collecting information on the use and effects of electric motor systems. If you become a participant in the Motor Challenge program, you can use the information developed for that program as a basis for preparing your EPAct Section 1605(b) report.

You should maintain records in your files containing the detailed calculations and data you used to estimate your emissions and emissions reductions.

You may choose to report through a third party, which could aggregate the emissions reductions for a group of entities with similar characteristics. The third party could ease the reporting burden on individual companies and provide an additional layer of confidentiality, since the contributions of any individual entity would not need to be identified in the report. (You should familiarize yourself with the confidentiality discussion in the General Guidelines.) A third party may also provide technical assistance in conducting the emissions-reducing projects and reporting. In this case, the emissions reduction might be reported jointly. Possible third parties include trade associations, engineering/energy service companies, and energy utility companies.

The reasons for third-party reporting could vary, depending on the type of third party. A trade association might wish to represent its industry's actions for public relations purposes or simply to provide additional confidentiality. An engineering/energy service company might wish to display its ability to save its clients money through its energy-saving measures or advice on environmental controls. A utility company could be jointly involved in demand-side management programs that reduce emissions. If you involve another party in identifying, implementing, or paying for the emission-reducing project, you should identify this party in your report to track possible multiple reporting. Similarly, if you are providing data on emission reductions to several third parties—for example, two trade associations of which you are a member—you should identify those parties.

A third-party reporter would develop aggregated reports and track the individual contributions of reporting entities. The third party would not be responsible for verification or certification; that responsibility remains with you as the reporting entity. If you report your emissions through a third party, you should retain in your files the information you used to compute your emissions and emissions reductions.

3.2 Organization of This Supporting Document

As described in the General Guidelines, EPAct Section 1605(b) addresses the reporting of annual emissions as well as emissions reductions and carbon sequestration. Section 3.3 provides guidance on reporting emissions, especially at the whole entity level. Section 3.4 builds on the discussion of project analysis in the General Guidelines and provides a framework for understanding how your emission reduction project relates to the reference cases, project effects, and estimation approaches described in the General Guidelines.

Rather than focus on specific industries, the remainder of this supporting document is organized by type of emissions-producing activity (energy use or industrial process operation). Table 3.2 indicates how the

Table 3.2 Where to Find Guidance for Reporting Industrial Emissions and Emissions Reductions

Type of Emissions or Reductions	Location
Total Emissions	Section 3.3
Reductions in Emissions from Energy Use	Section 3.5
Reductions in Emissions of Halogenated Substances from Halogenate Manufacture and Use and from Aluminum Production	Section 3.6
Reductions in Methane Emissions from Natural Gas Systems	Section 3.7
Reductions in Methane Emissions from Landfills	Section 3.8
Reductions in Methane Emissions from Coal Mines	Section 3.9
Reductions in Nitrous Oxide Emissions from Adipic Acid Plants	Section 3.10

document is organized and where you can find guidance for reporting emissions reductions for each type of activity. Sections 3.5 through 3.10 and Appendices 3.A through 3.F discuss methods for estimating emissions reductions. Section 3.5 provides general guidance for computing emissions reductions from energy savings, including the special cases of energy savings from fuel switching and cogeneration. Section 3.6 provides guidance for computing reductions of halogenated substance emissions.

Sections 3.7 through 3.9 provide specific guidance for computing reductions in methane emissions from coal mines, natural gas systems, and landfills, respectively. Finally, Section 3.10 provides guidance for computing reductions in nitrous oxide emissions from adipic acid plants. Note that some types of energy savings projects you may undertake will address the energy use of the buildings that house your industrial operations. These include projects to reduce the energy used for lighting, heating, cooling, and ventilation. Specific guidance for reporting emissions reductions resulting from decreased building energy use may be found in the supporting document for the residential and commercial buildings sector.

The most important greenhouse gas emitted from fuel combustion is carbon dioxide. Thus, carbon dioxide is the focus of the guidance on reporting emissions reductions related to energy use.

Carbon dioxide also is emitted directly from some manufacturing processes as an inherent byproduct of the production process—for example, carbon dioxide is created during the production of cement.[a] There are no economically feasible technologies available at this time to capture and dispose of carbon dioxide emissions. Thus, no specific guidance is provided for reporting reductions of carbon dioxide emissions that result directly from industrial processes (that is, unrelated to energy use). However, if you operate a cement plant or other carbon dioxide-emitting plant and you reduce production, close a plant, or in some other way reduce direct carbon dioxide emissions (for example, through a fundamental process change that reduces or eliminates the production of carbon dioxide), you may report the accompanying emissions reduction. In your project analysis, you will need to evaluate all the potential effects of your project, including an increase in production elsewhere to supply the market you are no longer supplying (see the General Guidelines, "How Should I Analyze Projects I Wish to Report?"). Any such emissions reduction report should conform to the principles for good project analysis described in the General Guidelines.

Similarly, no specific guidance is provided for reporting reductions of methane or nitrous oxide emissions from sources other than coal mines, natural gas systems, landfills, and adipic acid plants. You may report reductions from other sources in accordance with the project analysis principles described in the General Guidelines and this supporting document.

In general, you may report any type of project that reduces greenhouse gas emissions so long as you are able to perform a credible project analysis and meet the minimum reporting requirements described in the General Guidelines ("What Are the Minimum Reporting Requirements?"). You are not restricted to reporting only those projects mentioned explicitly in this document.

(a) Carbon dioxide is created during the calcination process when calcium carbonate ($CaCO_3$) is heated in a cement kiln to form lime (CaO) and carbon dioxide. Lime is also manufactured for other purposes, but cement production is the largest nonenergy source of industrial carbon dioxide emissions.

3.3 Estimating and Reporting Greenhouse Gas Emissions

The General Guidelines, "What is Involved in Reporting Emissions?" explain that reporting information on greenhouse gas emissions for the baseline period of 1987 through 1990 and for subsequent calendar years on an annual basis is considered an important element of this program. If you are able to report emissions information for your entire organization, you should consider providing a comprehensive accounting so that your audience can gain a clear understanding of your overall activities. As noted in the General Guidelines, some users of the database may find your reported estimates of emission reductions more credible when accompanied by data on your organization's total emissions for the year of the reduction, as well as for the baseline years 1987 through 1990 and subsequent years. You may wish to report this information for all or as much of your organization as possible, particularly if it would be important to users of your report.

A comprehensive emissions report would include your entity's total emissions from all on-site sources—building energy use, industrial process energy use, transportation energy use, on-site electricity generation, and direct emissions from industrial processes—as well as electric utility emissions associated with your purchased electricity. DOE encourages you to submit as comprehensive a report as possible, considering the feasibility and costs of obtaining the necessary data and the potential uses for your report.

Your emissions may be direct (from fuel use on-site or from industrial processes, coal mines, landfills, or natural gas systems) or indirect (from off-site generation of electricity you purchase) or a combination thereof. To report direct energy-related emissions, you can determine the amount and type of energy consumed as fuel[(a)] in the reporting year and, for each fuel, multiply the fuel use by the corresponding emission factor in the table in Appendix B or your site-specific emissions factor. To calculate emissions resulting from electricity purchases, you may use the default state level factors in Appendix C or calculate utility-specific factors using the guidance in the supporting document for the electricity supply sector. You will also need to determine your non-energy-related emissions (from industrial processes). For each gas, you should sum the emissions from direct energy use, electricity use, and industrial processes, and report the total.

Table B.1 in Appendix B provides emissions factors for various fuels. When the exact form of a fossil fuel is not known—for example, coal is burned, but the type is not identifiable—you should use an average emission/unit energy value for that fuel when computing total emissions. If you have specific data for your fuels and equipment indicating that an emission factor different from that in Table B.1 should be used, or if you use a fuel (such as a waste fuel) that is not listed in Table B.1, you are encouraged to use your own emissions factor. You must document the source of the emissions factor in your report.

(a) "Consumed as fuel" refers to the combustion of energy sources for heat and power rather than their use as feedstocks for chemical processes.

The case of biomass fuels present a special challenge to estimating emissions factors. In general, the emissions associated with switching to a biomass fuel depend on the reference case. For example, if the biomass represents waste from your operation that would have been burned in the reference case, your burning of that waste fuel represents no additional emissions. In this case, you could credibly assert that the emissions factor for your waste fuel is zero. Alternatively, if your biomass fuel comes from a managed source, determining the appropriate emissions factor is more complex. The supporting documents for forestry and agriculture provide some guidance on the computation of emission rates for such biomass-based fuels and the possible carbon sequestration that would arise if the biomass fuel source were a managed source. The carbon sequestration must be reported separately, however.

The case in which the biomass fuel would have been left to decay in the reference case is even more complex. In reality, the gas emitted from decaying biomass is a mixture of carbon dioxide and methane, with more methane emitted the more anaerobic the decay process. (For example, the fraction of methane in the emissions is higher if the biomass is wet.)

A conservative approach would assume that, for the biomass left to decay in the reference case, all the gas emitted was carbon dioxide. In this case, the amount of carbon dioxide assumed to be emitted from biomass sources would be the same in the project case and the reference case. In that case, any change in net emissions arises from reductions in the burning of fossil fuels.

A less conservative approach would account for the methane emissions that occurred in the reference case but are no longer occurring in the project case. In this case, you would be able to report an emissions reduction for methane. At the same time, you would have to report a smaller carbon dioxide emissions reduction (which makes up only a fraction of the reference case emissions rather than all of them). However, it requires considerably more data and analysis to take this approach. Also, attempting this approach without all the necessary data and analysis could cause some users of the database to lose confidence in your report. If you choose this approach to evaluate emissions reductions associated with using biomass fuels, you should explain carefully how you computed your reductions and what studies or other sources you used in doing so.

You may currently be reporting data on energy consumption to government or private organizations. You may wish to use these data in computing your total energy-related emissions. For example, the Energy Information Administration uses the Manufacturing Energy Consumption Survey (MECS) to collect data from a sample of manufacturers on the use of both electricity and direct fuels. Also, the Bureau of the Census uses the Census of Manufactures (CM) and the Annual Survey of Manufactures (ASM) to collect data on electricity consumption for the manufacturing industries. Although the data as reported are confidential, you can use the data you reported to these surveys as the basis for computing your total emissions. For example, if you are part of the MECS sample, the detailed data on fuel use that you reported could be used as a basis for computing carbon dioxide emissions from fossil fuel combustion and electricity use. Specifically, on the MECS reporting form, column 2, line 4, page 1, "total electricity received on-site," and column 9, lines A1-12, B1-8, C1-8, page 3, "energy sources consumed on-site," would provide the basis for calculating total emissions. If you are reporting your total entity emissions, you would need to compute separately any emissions from transportation vehicles, any non-energy related emissions from industrial processes and add these to your manufacturing energy-related emissions.

Some industry associations also collect energy data from their members for internal purposes. For example:

- The American Iron and Steel Institute collects energy data from its members.
- The Chemical Manufacturers Association surveys energy use and has adopted an Energy Efficiency Continuous Improvement Program.

You may wish to use data you reported to an industry association as the basis for computing your total energy-related emissions.

3.4 Performing Project Analysis

Your project may be defined as your entire organization, where you report the change in total emissions for your organization; several activities, perhaps as part of an energy efficiency program (these may include activities, such as materials processing, outside your organization); or only one activity, undertaken for its projected cost savings (such as a motor replacement project) or as a pilot project (such as an experimental industrial process change).

Your analysis of emissions reductions projects in the industrial sector should follow the process described in the General Guidelines:

1. Establish the reference case as a basis for comparison with the project.
2. Identify the effects of the project.
3. Estimate emissions for the reference case and the project.

The General Guidelines describe two types of reports: standard project reports and reporter-designed project reports. Standard project reports are those that use only default values provided in these guidelines—specifically, emissions factors (emissions per unit energy) and stipulated factors (standard energy savings or emissions reduction values for specific types of projects). Few standard projects exist for the industrial sector at this time. Most reports will use emissions factors together with energy savings estimates, but you will need to estimate the energy savings associated with your projects on a case-by-case basis. You will also need to compute the direct process emissions reductions associated with your project on a case-by-case basis. Thus, the rest of this chapter discusses only reporter-designed project reports. In a few instances (for example, methane emissions from natural gas systems), standard equations and default coefficients are available; these have been included where appropriate.

The project analysis process for the industrial sector is illustrated in Figure 3.1.

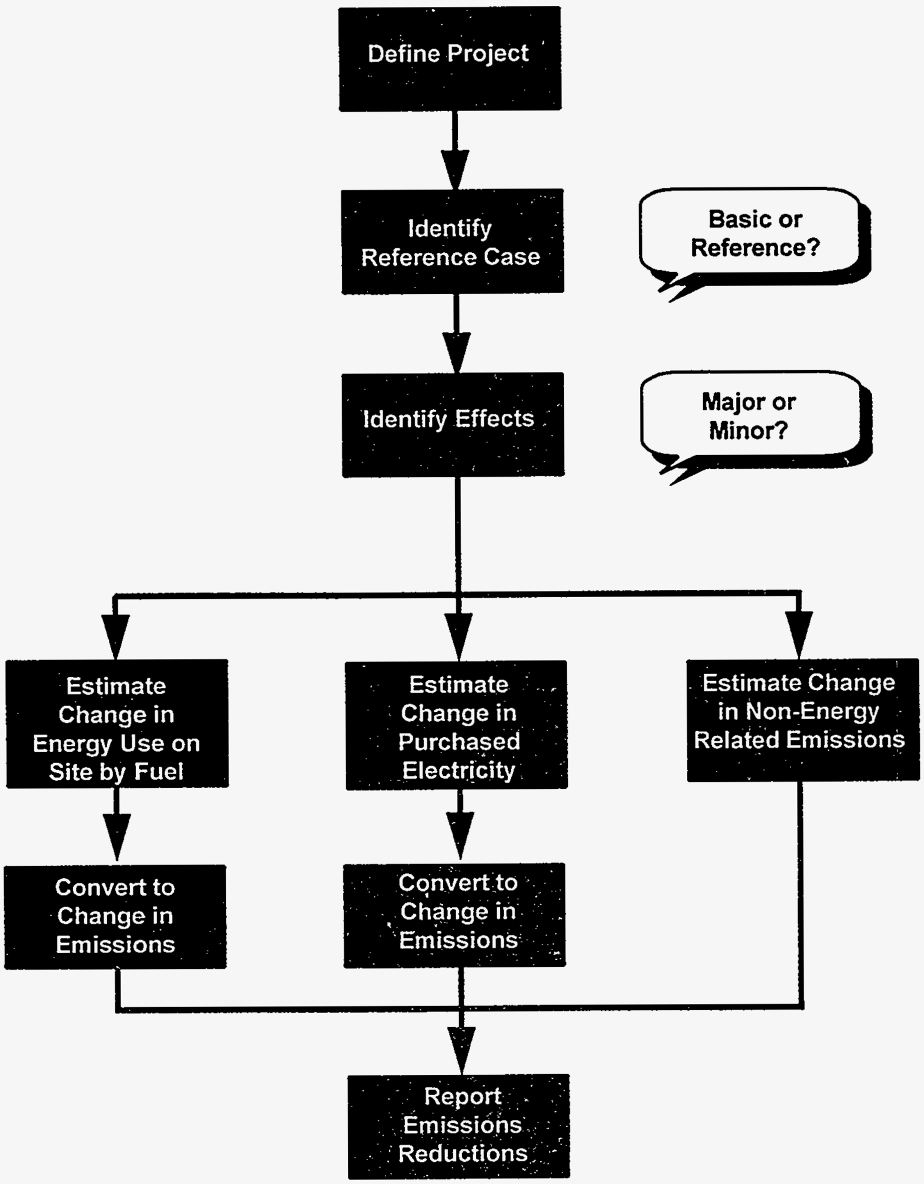

Figure 3.1. Project Analysis in the Industrial Sector Can Involve Both Energy-Related and Non-Energy-Related Emissions

3.4.1 Establish the Reference Case

As described in the General Guidelines (""What Should the Project Be Compared To?"), under this program you may choose a basic or a modified reference case. You should be thoroughly familiar with that discussion before proceeding with project analysis.

A basic reference case uses only historical emissions data as a basis for comparison with project emissions. Depending on the nature of and circumstances associated with your reporting, a basic reference case may provide a suitable and appropriate benchmark against which to compare project emissions. Some users of the EPAct 1605(b) database may have more confidence in reports that use a basic reference case than in reports that use a modified reference case.

In some cases, you may determine that a modified reference case is more appropriate. If so, you may choose to also report the emissions change using a basic reference case, to enable users of the database to evaluate U.S. emissions reduction efforts with respect to a historic baseline.

You should consider the obsolescence of your existing equipment as a factor in developing your reference case. This will be most important for developing a modified reference case. Three scenarios are possible:

- Your project involves replacing old equipment (of any vintage) with newer, more efficient equipment. Or, you expand production at your plant at the same time that you replace old equipment. You may use the current, before-project emissions (total or per unit production) as a basis for computing the reference case.

- You expand capacity using new, efficient equipment in the new capacity but your existing capacity uses obsolete equipment. In this case, it is not credible to assert that the new capacity would have used the obsolete equipment "but for" your project. Rather, you should use current equipment standards and/or appropriate industry averages to compute the modified reference case emissions. Your emissions reduction would result from the extent to which the efficiency of your new equipment exceeds these values.

- Your current capacity uses equipment that reflects current equipment standards and average (or better) industry practice. In this case, the reference case for expanded capacity could be based on the emissions (total or per unit production) of your current capacity.

You should use these guidelines to account appropriately for technology obsolescence when computing reference cases.

The remainder of this section discusses one type of modified reference case that is based on emissions per unit production. If you do not need this information, you can skip to Section 3.4.2.

A form of modified reference case that may be of particular interest to you as an industrial reporter is a reference case that accounts for production growth or capacity additions. In each of these situations, total emissions may be growing, but you may have taken steps to decrease the emissions per unit of production. In particular, many emission-reducing opportunities arise when new capacity investment decisions are being made.

In simple terms, you could compute emissions per unit of production before the emissions-reducing project is conducted or new, efficient capacity is added, and then determine what emissions "would have been" if the higher output were produced at the "old" emissions rate, possibly modified to account for technology obsolescence. This value is the modified reference case. Current emissions are compared to the reference emissions to determine the reportable reduction. (To be evaluated using a modified reference case based on unit production, the new capacity must produce outputs that you are currently producing, although it need not be in the same location as the existing capacity.)

If you add capacity to produce a good that you are not currently producing, or if you need to account for technology obsolescence for expanded capacity, then you must turn to sources other than your own production history to determine the emissions per unit production for the reference case. You should provide a credible estimate for the reference case. While no definitive guidance is available on sources for such estimates, possible sources include engineering firms that build similar facilities and trade associations that have data on industry averages of energy use and output. Because these sources are not within your control, care should be taken to ensure that the data are credible. You are responsible for certifying the accuracy of your report, so reference case estimates for such cases should be conservative (that is, they should not overstate the emissions per unit of production). If you have documented information that indicates your company considered and evaluated lower-efficiency options for the new capacity but chose a higher efficiency option, you may be able to use such data to estimate your reference case. In using these data, you should avoid the use of "straw man" proposals that maximize your reported emissions reductions. Instead, use conservative estimates of reference case emissions.

Measuring the "unit of production" presents many challenges. Few entities produce a single homogeneous product. Even for basic materials industries such as paper, steel, and glass, changes in product mix might cause the emissions per ton of product to rise, while allowing emissions per dollar value of shipments (or dollar of value added) to stay constant or to even decline (if the dollar value of the product is rising). It is difficult to say which measure of production is "correct." Higher-value products produced with the same level of emission per ton of product may be beneficial to the economy, because economic growth occurs without increased emissions. Valuing output in monetary terms also is complicated by the need to use price deflators to compare this measure of output across time periods.

Given the difficulties in using a dollar value (shipments or value added) measure of output, you should use only physical measures of output (for example, tons of steel, numbers of items) to compute emissions per unit of production. You may calculate emissions per unit of production for your entire entity or for discrete projects. In the latter case, you need not measure production in terms of your final, saleable product. A well-defined, intermediate product can be used as the basis for a modified reference case based on unit production. This approach would be useful if you have a primary processing stage, but also several finishing stages that produce different final products. Another useful measure of intermediate product as a unit of production is an energy service. For example, if "delivered steam" is viewed as an intermediate product, then a unit-of-production approach may capture the emissions reductions associated with expanding steam capacity coupled with improved efficiencies.

In summary, when you are using a modified reference case (mref) based on emissions per unit of production, you would compute the reference and project case emissions as follows:

$$\text{Emissions}_{mref} = \text{Emission Rate}_{old} \bullet \text{Production}_{new}$$

$$\text{Emissions}_{proj} = \text{Emission Rate}_{new} \bullet \text{Production}_{new}$$

where the "old" emissions rate is the emissions per unit production before the project or for the existing capacity (accounting appropriately for technology obsolescence), the "new" emission rate is the emissions per unit production after the project or for the new capacity, and the "new" production is the production level after the project or for the new capacity.

For comparison purposes, the basic reference case (bref) emissions would be computed as follows:

$$\text{Emissions}_{bref} = \text{Emissions Rate}_{old} \bullet \text{Production}_{old}$$

where the "old" production is the production level before the project or for the existing capacity (accounting appropriately for technology obsolescence).

3.4.2 Identify the Effects of the Project

Your report should address all the effects of your project that you can identify, as described in the General Guidelines. You should quantify these effects whenever possible. To determine whether you have identified all project effects, you should consider questions such as the following:

- Has production been reduced somewhere in your organization that was replaced by other similar productive activities within or outside of your organization? (Any emissions reductions that result from a plant closure should be so identified.)

- Have you begun purchasing energy services, materials, or goods that were previously produced internally, or have you shifted production to outside the boundaries of the project you are reporting?

Example 3.1 - Modified Reference Case

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A primary aluminum smelting facility in Texas upgraded the control system on one of its potlines,[a] resulting in improvements in energy efficiency. At the same time its production increased from 350 million pounds of aluminum per year to 450 million pounds per year. Careful records are kept on energy consumption for the smelting process. After sufficient time passed to account for short term fluctuations in process parameters, the plant engineers estimated that the energy intensity of smelting dropped from 6.8 kWh/lb to 6.6 kWh/lb. Because the facility did not have information on the specific emissions factor for its purchased electricity, it used the combined emissions factor for Texas from Appendix C to estimate carbon dioxide emissions.

Before the project the total electricity used for smelting was

$$6.8\ \frac{\text{kWh}}{\text{lb}} \bullet 350\text{x}10^6\ \frac{\text{lb}}{\text{year}} = 2.38\text{x}10^9\ \frac{\text{kWh}}{\text{year}}$$

In Appendix C the carbon dioxide emission factor for Texas is given as 0.776 short tons (ST) per megawatt hour (MWh). (Other greenhouse gases were ignored for purposes of this example.) Thus, before the project total emissions were

$$2.38\text{x}10^9\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 1.85\ \frac{\text{million ST CO}_2}{\text{year}}$$

This is the basic reference case.

The plant production increased from 350 to 450 million pounds per year at the same time that the energy intensity of smelting decreased. Without the energy efficiency program the emissions level with the increased production (the modified reference case) would have been

$$6.8\ \frac{\text{kWh}}{\text{lb}} \bullet 450\text{x}10^6\ \frac{\text{lb}}{\text{year}} = 3.06\text{x}10^9\ \frac{\text{kWh}}{\text{year}}$$

$$3.06\text{x}10^9\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 2.37\ \frac{\text{million ST CO}_2}{\text{year}}$$

However, with the energy efficiency program, emissions were

$$6.6\ \frac{\text{kWh}}{\text{lb}} \bullet 450\text{x}10^6\ \frac{\text{lb}}{\text{year}} = 2.97\text{x}10^9\ \frac{\text{kWh}}{\text{year}}$$

$$2.97\text{x}10^9\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 2.3\ \frac{\text{million ST CO}_2}{\text{year}}$$

Thus,

$$\begin{aligned}\text{Annual Emissions Reduction} &= \text{Emissions}_{\text{ref}} - \text{Emissions}_{\text{proj}} \\ &= 2.37\ \text{million ST CO}_2 - 2.3\ \text{million ST CO}_2 = 0.07\ \text{million ST CO}_2\end{aligned}$$

As a result of its control system upgrade, the smelting plant could report a 70,000 ST per year emissions reduction relative to the modified reference case, even though actual carbon dioxide emissions went up by 450,000 ST per year relative to the basic reference case.

(a) A potline is a series of electrolytic cells used to produce primary aluminum from alumina.

Example 3.2 - Modified Reference Cases Using Intermediate Products

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(a) A steel mill increased its electric-arc furnace capacity and upgraded to a more efficient transformer. The mill produced a variety of construction products, but the output of the furnace could be measured in tons of steel poured. Electricity use per ton of "steel poured" (and used to produce final goods) could have been computed from metered energy consumption and internal accounts of steel furnace output. These data, before and after the project, could have been used to compute the modified reference case and the reduction in carbon dioxide emissions.

(b) An organization added new boiler capacity but also implemented several boiler/steam-efficiency improvements. By measuring the amount of steam delivered (with no change in pressure and temperature) as an intermediate output, the organization developed a modified unit-of-production reference case.

Example 3.3 - Identifying Project Effects

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(a) A reporting entity with two facilities reduced its energy use in the first facility by consolidating its materials processing in the second facility. The first facility's energy use declined but the second facility's energy use increased. However, the consolidation improved efficiency and reduced total energy use by the two facilities.

The entity could report only the emissions reductions resulting from net reductions in energy use. It could choose to either

(1) consider the first facility as the project and report the increased energy use at the second facility as an off-site project effect subtracting it from the reduced energy use being reported for the first facility, or

(2) report the net change in energy use at the entity-wide level.

Energy use and associated greenhouse gas emissions at both facilities must be accounted for because the reduction in energy use at the first location *caused* energy use to increase at the second location.

(b) An entity with two facilities implemented an electricity-efficiency program in one facility and reduced consumption by 50 percent. In the second facility it began to make a new product whose production required large amounts of electricity. The entity's total electricity consumption rose or stayed constant.

In this case, the entity could report the efficiency program and its related emissions reductions even if total emissions were increasing. The increases in electricity consumption and associated emissions at the second location *were not caused by* the actions taken to reduce electricity use at the first location. However, the entity may choose to also report its total emissions, recognizing that this would make its report more credible in the eyes of some reviewers.

Projects in the industrial sector run the gamut from discrete, well-defined projects (for example, replacing 10 motors with high-efficiency motors or replacing the use of a halogenated blowing agent with a nonhalogenated agent) to projects that can have both reinforcing and antagonistic effects within and outside of a reporting entity (for example, a set of efficiency projects that involve cogeneration, motor upgrades, and fuel switching). When projects begin to interact such that the effects of each project cannot clearly be separated out, you should consider reporting your entity-level emissions reduction rather than the emissions reduction associated with individual projects. For example, you may wish to compute the emissions associated with your total energy use before and after the project. After accounting for other effects (for example, associated with outsourcing or cogeneration), you can report the reduction in total entity emissions. If you choose to report in this way, your report should identify the specific projects that you undertook to reduce emissions, even though you may not be able to estimate the emissions reduction associated with each individual project.

3.4.3 Estimate Emissions for the Reference Case and the Project

Your analysis of emissions for the reference case and the project and your report must meet the minimum reporting requirements described in the General Guidelines ("What Are the Minimum Reporting Requirements?"). Your report will lose credibility if you do not use estimation practices commonly acceptable in the professional community. You may want to review the guidance provided in Sections 3.5 through 3.10 of this supporting document that describes procedures for estimating energy savings and emissions reductions for several types of emissions-reducing measures.

The guidelines recognize three categories of data:

Physical Data. This is information that describes the activities involved in your project and must be included in every report. For example, how many and what type of motors were replaced? What types of operational practices were improved? What types of process changes were made? Section 3.5.1 describes the Assessment Recommendation Code (ARC) system, which is used to identify actions taken to reduce energy use. All other actions, and energy-related actions not listed in the ARC system, should be identified clearly in your report.

Default data. This is information provided in the supporting documents to assist you in evaluating the emissions or sequestration effects of your project. Using default data increases your ease of reporting (in some cases, allowing you to report when you might not otherwise have enough data). However, using default data may decrease precision and, because the defaults are generally conservative, your emissions reductions may appear lower than they actually are. There are two categories of default data:

Emissions factors. These are factors that allow you to convert information about a change in energy use to an estimated change in greenhouse gas emissions. Some emissions factors are rather precise. For example, the change in direct emissions of carbon dioxide from a reduction in methane combustion is essentially constant, regardless of when or where the change took place. Other emissions factors, and particularly those for off-site emissions, are less precise.

For example, Appendix C provides emissions factors for electricity on a state-by-state basis. However, the effect that a change in electricity consumption has on emissions will vary by location within the state, the time of day, and the season that a change occurs.

Stipulated factors. These are factors that allow you to convert physical data about your project into estimates of changes in energy use or greenhouse gas emissions. The supporting documents provide this information for a few types of projects where the scope and nature of the project can be clearly defined and where the effects on emissions can be predicted with relative certainty.

Few stipulated factors are available for the industrial sector at this time, particularly for energy savings; those factors provided in this supporting document address non-energy-related emissions. (For example, Table 3.5 in Section 3.7.3 provides stipulated emissions reduction factors for selected natural gas system projects.) An exception is a project that affects the energy use of industrial buildings (primarily lighting, heating, cooling, and ventilation). The supporting document for the residential and commercial buildings sector provides stipulated factors for converting information about certain building energy-efficiency projects into estimates of fuel savings. These estimates can be combined with default emissions factors to estimate reductions in greenhouse gas emissions. You should refer to the supporting document for the residential and commercial buildings sector for technical guidance on analyzing building-related projects.

Reporter-Generated Data. These are data you develop as a basis for estimating the effects of your project. There are two categories of reporter-generated data:

Measured Data. These are data collected directly from the project that you use in estimating your project's accomplishments. For example, you may measure emissions or emissions reductions directly or meter energy use or other parameters (such as production) at the level of an entire entity or at a lower level (for example, a plant within an organization, a production line within a plant, a portion of a natural gas system).

Engineering Data. These are data that you derive from various sources, such as engineering manuals, manufacturer's equipment specifications, surveys, academic literature, and professional judgment.

Your choice of estimation methods will be constrained by the availability of data. For example, you may estimate emissions reductions from an efficiency project using measured data as well as engineering estimation. Using several methods and comparing the results may increase the confidence that users of the EPAct 1605(b) database will have in your estimations.

3.5 Estimating Emissions Reductions Associated with Energy Use

This section describes how to estimate energy savings for energy conservation, fuel switching, cogeneration, and recycling projects and how to translate the computed savings into emissions reductions. When the actions that reduce energy consumption include a reduction in production or closure of a plant or production line (without replacing that activity elsewhere), this action is reportable; however, no specific guidance for such reports is provided here. Note that you should identify these as the emissions-reducing activities in your report and take care to ensure that all project effects are accounted for.

Many types of activities may be undertaken to reduce energy use and associated emissions of carbon dioxide and other greenhouse gases. These include the following:

- use of energy efficient equipment and processes
- switching from high-emitting fuels to lower-emitting fuels
- cogenerating steam and electricity
- improving operational and maintenance practices
- recycling input materials
- undertaking efforts to improve productivity—that is, to produce the same level of goods and services with fewer inputs.

All of these types of activities have the potential to reduce emissions and can be reported to the EPAct Section 1605(b) program. Other emissions-reducing projects that are not explicitly mentioned can also be reported.

3.5.1 Identification of Activities

The activities you undertook to reduce energy use should be identified using the DOE's Assessment Recommendation Codes (ARCs), which are listed in Appendix 3.A of this supporting document. The ARC system is a hierarchical categorization of activities—for example, combustion systems are ARC 2.1, boilers are ARC 2.1.2, and boiler tube maintenance is 2.1.2.3.2. Activities that reduce energy use directly are listed in Section 2 of the ARCs. However, activities in other sections that are directed at waste minimization, recycling, and productivity enhancements may reduce energy use as a byproduct of their primary focus. You should identify the ARC codes corresponding to all activities you undertook that contribute to the emissions reduction you are reporting. If your project is not listed in the ARC system, you should describe it in your report. Be sure to identify the numbers of projects (for example, number of motor replacements).

The major categories of the ARC system that address reduced energy use are shown in Table 3.3.

Table 3.3 Major ARC System Categories

ARC Category	ARC Section
Combustion Systems	2.1
Thermal Systems	2.2
Electrical Power	2.3
Motor Systems	2.4
Industrial System Design	2.5
Miscellaneous Operational Changes	2.6
Buildings and Grounds	2.7
Administrative	2.8
Alternative Energy Usage	2.9
Shipping, Distribution, and Transportation	2.10

These categories include some actions that are common to the residential and commercial buildings sector (for example, Buildings and Grounds, ARC 2.7) and the transportation sector (for example, Shipping, Distribution, and Transportation, ARC 2.10). You should consult the supporting documents for the residential and commercial buildings sector and the transportation sector, respectively, for technical guidance on reporting energy savings and associated emissions reductions for these actions.

The ARC system is least likely to be complete in describing industry-specific process changes or improvements in management and other productivity-enhancing activities. When the ARCs are not adequate to describe your project, you should briefly describe the project using standard industry terminology.

3.5.2 Identifying the Effects of the Project

You must identify the effects of your project(s), as described in Section 3.4.2 of this supporting document and in the General Guidelines. Your report should address all the effects that you can identify - not just the obvious, intended effects, but also less noticeable, unintended effects. You should quantify these effects whenever possible.

3.5.3 Estimating Project Effects

If your project affects the use of a single fuel, your annual emissions reduction of a given greenhouse gas can be computed very simply:

$$\text{Emissions Reduction} = \left(E_{reference} - E_{project}\right) \bullet F_j$$

where E = annual energy use, in Btu or kWh or a multiple thereof; and

F_j = emissions factor (emissions per unit energy) for fuel j, obtained from Appendix C (for electricity) or Appendix B (for other fuels), or computed using your own data.

In the case of electricity use you should compute the emissions reduction or increase for both carbon dioxide and nitrous oxide (N_2O); for on-site fuel combustion you need only be concerned with carbon dioxide. (You can also report changes in the emissions of other affected gases.) Example 3.4 illustrates the calculation process for a change in electricity use.

When more than one fuel is affected you will need to perform the calculations separately for each fuel and sum the overall effects for each activity and greenhouse gas. For each gas, the emissions reduction (or increase) for *n* fuels would be computed as follows:

$$\text{Emissions Reduction} = \sum_{j=1}^{n} (E_{j,reference} - E_{j,project}) \bullet F_j$$

where E_j = annual energy use, in Btu or kWh or a multiple thereof, for fuel j

F_j = emissions factor (per unit energy) for fuel j, obtained from Appendix C (for electricity) or Appendix B (for other fuels), or computed using your data.

Examples 3.5 and 3.6 illustrate the calculation process for changes in multiple fuels.

Example 3.4 - Estimating Project Effects for Reduction in Use of a Single Fuel

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

As a result of an energy audit, an integrated pulp and paper mill located in Washington determined that compressor motors used to provide air to the wastewater treatment system were operating at only about 40 percent of rated load, or 80 horsepower. Because the load is relatively constant, the mill decided to replace these 200 horsepower motors with 100 horsepower high-efficiency motors. The plant uses six of these motors.

Other changes at the plant had affected total electricity use, so plant-wide electricity purchase records could not be used to compute the electricity savings from the motor replacement program. Also, motor electricity use was not metered separately from other electricity uses. Thus, engineering estimation was required to compute motor electricity use. Because the number of motors and their operating conditions did not change, the plant engineer chose a basic reference case computed using data from the year just prior to the motor replacement project.

Manufacturer's data were used to determine the nominal, full load efficiency of the motors. The original motors were rated at 90.2 percent efficiency, the new motors at 95.4 percent efficiency. While the new motors were expected to operate at about the rated efficiency for the actual load conditions (80 percent), the low loading on the original motors was likely to impact the performance. A literature value of 88 percent was found for half-load performance of a similar motor. Since no information was available for the efficiency of the motor when operating at only 40 percent of rated capacity, this value was used to estimate energy savings.

The wastewater treatment process was a continuous operation, so the motors ran 24 hours a day year round. Plant maintenance records indicated that, on average, the motors were down for an average of two days per year for maintenance on both the motors and the aeration system. The new motors were expected to operate in the same way, for an annual operating time of 8,712 hours. Electrical power consumption was calculated by dividing the actual load by the motor efficiency and converting to kilowatts, then multiplying by annual hours of operation.

Reference case energy consumption:

$$\frac{80 \text{ hp / motor}}{0.88} \bullet 0.7457 \frac{\text{kW}}{\text{hp}} = 67.8 \text{ kW / motor}$$

$$67.8 \frac{\text{kW}}{\text{motor}} \bullet 8712 \frac{\text{hours}}{\text{year}} \bullet 6 \text{ motors} \bullet \frac{1 \text{ MW}}{1{,}000 \text{ kW}} = 3{,}544 \frac{\text{MWh}}{\text{year}}$$

Project case energy consumption:

$$\frac{80 \text{ hp / motor}}{0.954} \bullet 0.7457 \frac{\text{kW}}{\text{hp}} = 62.5 \text{ kW / motor}$$

$$62.5 \frac{\text{kW}}{\text{motor}} \bullet 8712 \frac{\text{hours}}{\text{year}} \bullet 6 \text{ motors} \bullet \frac{1 \text{ MW}}{1{,}000 \text{ kW}} = 3{,}267 \frac{\text{MWh}}{\text{year}}$$

The reduction in electricity use was thus 277 MWh/year. Because the mill did not have information on the specific emissions factor associated with its purchased electricity, it used the combined emissions factor for Washington from Appendix C to compute the corresponding emissions reductions. In its report, the mill identified its action as ARC 2.4.1.2.1 (replace oversize motors with optimum size) and ARC 2.4.1.2.4 (use most efficient type of electric motors).

	CO_2	N_2O
Emission Factor (lb/MWh)	306	0.0461
Annual Emission Reduction (lb)	84,762	12.8

Example 3.5 - Estimating Project Effects for Changes in Multiple Fuels

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Lumber produced at a facility in Georgia was dried in steam-heated kilns. The primary fuel used to generate the steam was natural gas, but because of an interruptible contract for delivery of this fuel, the boiler was outfitted to burn No. 2 fuel oil as well. In upgrade operations a new, higher efficiency boiler was installed. The mill estimated that emissions from the steam system would drop due to improved boiler efficiency.

Because production levels are expected to remain constant, there will be no changes in steam demand. The plant engineer therefore chose a basic reference case. However, because fuel use varied from year to year as a result of the interruptible natural gas contract, the plant engineer computed the reference case energy use from the average oil and gas purchases (based on plant records) for the three years prior to replacing the boiler. Project case fuel use will differ from the reference case because of the improved boiler efficiency as well as year-to-year fluctuations in the fuel mix. In the first year after the boiler was replaced, natural gas consumption increased from 147 million cubic feet (the reference case average) to 155 million cubic feet, while fuel oil consumption decreased from 219,000 gallons (the reference case average) to 105,000 gallons.

Emissions reductions were calculated from the net change in energy consumption and the emission factors in Appendix B. Natural gas has an energy value of 1,032 Btu/cubic foot, so the energy content of the natural gas used and the associated emissions were calculated as

$$\text{Natural gas use}_{ref} = 147 \text{ million cubic ft} \bullet 1{,}032 \frac{\text{Btu}}{\text{cubic ft}} = 152 \text{ billion Btu}$$

$$\text{Emissions}_{ref} = 152 \text{ billion Btu} \bullet 58.2\text{x}10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 8{,}846 \text{ ST } CO_2$$

$$\text{Natural gas use}_{proj} = 155 \text{ million cubic ft} \bullet 1{,}032 \frac{\text{Btu}}{\text{cubic ft}} = 160 \text{ billion Btu}$$

$$\text{Emissons}_{proj} = 160 \text{ billion Btu} \bullet 58.2\text{x}10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 9{,}312 \text{ ST } CO_2$$

No. 2 fuel oil is a form of distillate fuel oil, so the energy value of this fuel was calculated as

$$\text{Oil use}_{ref} = 219{,}000 \text{ gallons} \bullet 138{,}700 \frac{\text{Btu}}{\text{gallon}} = 30.4 \text{ billion Btu}$$

$$\text{Emissions}_{ref} = 30.4 \text{ billion Btu} \bullet 79.9\text{x}10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 2{,}429 \text{ MT } CO_2$$

$$\text{Oil use}_{proj} = 105{,}000 \text{ gallons} \bullet 138{,}700 \frac{\text{Btu}}{\text{gallon}} = 14.6 \text{ billion Btu}$$

$$\text{Emissions}_{proj} = 14.6 \text{ billion Btu} \bullet 79.9\text{x}10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 1{,}167 \text{ ST } CO_2$$

Example 3.5 - (cont'd)

As a result of the project, natural gas use and associated emissions went up and oil use and associated emissions went down relative to the reference case. The resulting changes in emissions are

For natural gas:

$$\text{Emissions}_{ref} - \text{Emissions}_{proj} = -\ 466 \text{ ST } CO_2 \text{ (an increase)}$$

For oil:

$$\text{Emissions}_{ref} - \text{Emissions}_{proj} = 1{,}262 \text{ ST } CO_2 \text{ (a decrease)}$$

No other effects within or outside the plant were anticipated. The total reportable emissions decrease is 796 short tons of carbon dioxide. In its report, the mill identified its action as ARC 2.1.2.2.4 (replace boiler). In subsequent years, the lumber facility will monitor its annual fuel consumption and compute a new emissions reduction for each year relative to the same basic reference case used for this year's calculation.

However, if you are not reporting entity-wide fuel use reductions, you may not have data (metered or from plant records) on fuel use for the specific energy use categories affected by your project (for example, motors, boilers). In this case, you will need to use engineering estimation to derive the energy use for the reference case and project case. You should be sure to account for the actual utilization rate of your equipment. Example 3.6 illustrates this type of calculation.

Example 3.6 - Estimating Project Effects for Multiple Projects and Fuels

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A lumber mill (such as that in Example 3.5) that dried its lumber in steam-heated kilns undertook two projects: replacement of the obsolete boiler and insulation of the steam lines between the boiler and the kiln. In this case, the use of natural gas and oil for uses other than in the boiler obscured the actual changes in energy consumption associated with these projects. Emissions reductions were calculated on the basis of the estimated efficiency of the existing system and the estimated results of the two projects.

Annual production of lumber at the mill is 54 million board feet (bf), but only half of this is dried. The estimated steam use in the kiln was 6,075 Btu/bf, but 10 percent of the steam energy generated was lost in the steam pipes. The old boiler operated at 80 percent efficiency. The overall efficiency of the boiler/steam delivery system was thus 72 percent (80% x 90%), such that 8,438 Btu/bf (6,075/0.72) of input energy was required for the boiler.

The total reference case energy use in the boiler was calculated from the energy intensity of drying, the production level, and the fraction of production that is dried:

$$\text{Energy use}_{ref} = 8{,}438\ \frac{\text{Btu}}{\text{bf}} \bullet 54\text{x}10^6 \text{ bf} \bullet 0.5 = 227.8 \text{ billion Btu}$$

On average the boiler was operated 10 months of the year on natural gas and 2 months on oil. Thus, of the total energy input, 83 percent was supplied by natural gas (189.1 billion Btu) and 17 percent was supplied by oil (38.7 billion Btu). For this example, these fuel shares are assumed to remain constant between the (basic) reference case and the project case.

Example 3.6 - (cont'd)

Reference case emissions were calculated using the emissions factors from Appendix B.

For natural gas:

$$\text{Emissions}_{ref} = 189.1 \times 10^9 \text{ Btu} \bullet 58.2 \times 10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 11{,}006 \text{ ST } CO_2$$

For oil:

$$\text{Emissions}_{ref} = 38.7 \text{x} 10^9 \text{ Btu} \bullet 79.9 \text{x} 10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 3{,}092 \text{ ST } CO_2$$

Total reference case carbon dioxide emissions were thus 14,098 short tons.

After the project the boiler efficiency was expected to increase to 84 percent and losses from the steam pipes were expected to decrease 80 percent, to 2 percent of steam energy produced. The improved efficiency of the boiler/steam delivery system is thus 82.3 percent (84% x 98%). In order to deliver 6,075 Btu, the boiler will consume only 7,382 Btu of fuel. Total boiler energy use was thus:

$$\text{Energy use}_{proj} = 7{,}382 \frac{\text{Btu}}{\text{bf}} \bullet 54 \text{x} 10^6 \text{ bf} \bullet 0.5 = 199.3 \text{ billion Btu}$$

Based on the assumption that fuel shares remained constant, 165.4 billion Btu was natural gas and 33.9 billion Btu was oil. Project case emissions are computed below.

For natural gas:

$$\text{Emissions}_{proj} = 165.4 \text{x} 10^9 \text{ Btu} \bullet 58.2 \text{x} 10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 9{,}626 \text{ ST } CO_2$$

For oil:

$$\text{Emissions proj} = 33.9 \text{x} 10^9 \text{ Btu} \bullet 79.9 \text{x} 10^6 \frac{\text{ST } CO_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 2{,}709 \text{ ST } CO_2$$

Total project case emissions were thus 12,335 short tons of carbon dioxide, for a reportable emissions reduction of 1,763 short tons. In its report, the mill identified its actions as ARC 2.1.2.2.4 (replace boiler) and ARC 2.2.1.3.1 (insulate steam lines).

In Examples 3.5 and 3.6, the reporting entity could use data on entity-wide fuel use to compute emissions if (1) it is reporting at the entity level or for a collection of projects, or (2) it is reporting for specific projects, and no other changes have occurred that affect energy use.

As illustrated in Example 3.7, some fuel switching projects involve the substitution of electro-technologies for fossil fuel-fired technologies, with a resulting decrease in emissions.

Example 3.7 - Estimating Project Effects for Electrification

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A food processing company in New Jersey is considering replacing its equipment that removes water from a product. Currently, the company evaporates the water by firing natural gas. The alternative method under consideration is freeze concentration. The company is considering the change for energy efficiency reasons but has decided to determine the associated emissions reduction benefit for possible reporting to the DOE's voluntary program.

For the plant's level of production, 800 lbs of water must be removed per hour, 40 hours per week, 50 weeks per year. The total amount of energy required to do this using natural gas is 540 Btu/lb; the total amount of energy required using freeze concentration (powered by electricity) is 100 Btu/lb. Because the company did not have information on the specific emissions factor associated with its purchased electricity, it used the combined emissions factor for New Jersey from Appendix C to compute electricity-related emissions.

For natural gas:

$$\text{Energy consumption}_{ref} = 800\ \frac{\text{lb}}{\text{hr}} \bullet 40\ \frac{\text{hr}}{\text{wk}} \bullet 50\ \text{wk} \bullet 540\ \frac{\text{Btu}}{\text{lb}} = 8.64\text{x}10^8\ \text{Btu}$$

Using an emissions factor from Appendix B,

$$\text{Emissions}_{ref} = 8.64\text{x}10^8\ \text{Btu} \bullet 58.2\text{x}10^6\ \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1\ \text{quad}}{10^{15}\ \text{Btu}} = 50.3\ \text{ST CO}_2$$

For electricity:

$$\text{Energy consumption}_{proj} = 800\ \frac{\text{lb}}{\text{hr}} \bullet 40\ \frac{\text{hr}}{\text{wk}} \bullet 50\ \text{wk} \bullet 100\ \frac{\text{Btu}}{\text{lb}} = 1.6\text{x}10^8\ \text{Btu}$$

$$= \frac{1.6\text{x}10^8\ \text{Btu}}{3412\ \text{Btu/kWh}} = 4.69\text{x}10^4\ \text{kWh}$$

Using the electricity emissions factor for New Jersey from Appendix C,

$$\text{Emissions}_{proj} = 4.69\text{x}10^4\ \text{kWh} \bullet \frac{1\ \text{MWh}}{10^3\ \text{kWh}} \bullet 0.387\ \frac{\text{ST CO}_2}{\text{MWh}} = 18.2\ \text{ST CO}_2$$

$$\text{Emissions reduction} = \text{Emissions}_{ref} - \text{Emissons}_{proj} = 50.3\ \text{ST CO}_2 - 18.2\ \text{ST CO}_2 = 32.1\ \text{ST CO}_2$$

Some additional types of projects that affect energy intensity are described in Example 3.8.

Example 3.8 - Additional Projects That Affect Energy Intensity

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

- Air was substituted for steam to atomize oil (ARC 2.2.1.5.10). This was reflected in a lower energy intensity (energy use per unit of output) of the activity of atomizing oil. In other words, the demand for the energy service of steam to atomize oil was reduced or eliminated.
- Scrap glass was recycled internally by an entity as an input feedstock (ARC 3.5.2.1.1). This was reflected in a lower energy intensity, for the activity of producing primary glass.
- A smaller boiler was installed to increase the high fire duty cycle. This was reflected in a lower energy intensity of the activity of delivering steam. It also implied a smaller capacity and a higher utilization rate that should be accounted for in the project analysis.

3.5.4 Estimating Project Effects: Fuel Switching

When your project consists of switching from a higher-emitting fuel source to a lower-emitting fuel source, you should compute the emissions with the old fuel and new fuel and report the difference (if emissions have decreased) using the methods described in Section 3.5.3. When one of the fuels involved is electricity, the electricity emissions factors in Appendix C of this supporting document should be used unless you have more specific factors from your electricity supplier.

If you switch from purchasing electricity to generating your own (for example, using a diesel generator, a set of photovoltaic cells, or a boiler), emissions reductions may occur (unless the purchased electricity was generated with hydroelectric, renewable, or nuclear fuels). You should provide the carbon emissions rate for your self-generated electricity to compute the emissions reduction. To compute this, you will need the heat rate (Btu/kWh) for your electricity-generating equipment and fuel. You would multiply the heat rate by the carbon dioxide emissions factor for your fuel (from Appendix B) to obtain the emissions rate (metric tons/kWh). If you have data on the specific carbon content of your fuel that differ from Table B.1, you are encouraged to use them. You must document the source of your data in your report. If the fuel for your self-generation is renewable (for example, photovoltaic), the appropriate carbon dioxide emissions rate (zero) would be used to compute the project case emissions (which may also be zero in this case).

3.5.5 Estimating Project Effects: Cogeneration

One type of project that involves changes in more than one fuel (usually fuel combusted on site and purchased electricity) is cogeneration, which is defined as the combined generation and use of electricity and steam or heat, where both were previously produced or purchased separately. Under these conditions, cogeneration improves efficiency and reduces greenhouse gas emissions by displacing electricity purchases with power created from an "existing" source or demand for steam. To accurately account for the net greenhouse gas emissions reductions from cogeneration, you will need to measure or estimate two elements: the increase (if any) in fuel input and the displacement of purchased electricity. Converting boiler steam systems to produce electricity and useful steam sometimes involves an increase in steam output (temperature, pressure, etc.) and a corresponding increase in energy input. These increases may or may not be offset by boiler efficiency improvements or replacement with gas turbines, but usually are more than offset by the emissions savings related to displacement of purchased electricity. The steps in estimating the effects of a cogeneration project are described below.

Step 1: Compute the change in input fuel use. (The increased carbon dioxide emissions from increased fuel use must be subtracted from the emissions reduction derived from displacing purchased electricity.) This analysis assumes that the steam output of the old boiler and the new cogeneration system are the same—that is, the system is sized to the steam demand at the plant. If capacity is being expanded, a reference case modified to account for the increased production may be appropriate.

Three possible data sources can be used to compute the change in carbon dioxide emissions resulting from changes in input fuel use:

- **Entity-wide fuel use**—If the cogeneration system is the only change that affects energy use, entity-wide data can be used for the reference and project cases.

- **Measured "before and after" energy input**—Since the cogeneration system may be a significant portion of your organization, you may have kept records of fuel use for the original steam production.

- **Engineering estimation**—Since engineering estimation relies on the accuracy of assumptions about utilization rates and energy intensities, it is less desirable than measured data but can be used if such data are not available or if other changes at your organization have made it impossible to accurately infer the change in energy input to the cogeneration system.

Step 2: Measure or estimate the central station electricity generation that is displaced by cogenerated power. Three methods are available for deriving this value:

- **Metered output from the cogeneration units**—This is the most accurate and the preferred method to estimate the displaced central-station electricity generation.

- **Engineering estimates of the output from the cogeneration units**—The accuracy of this method is contingent on the accuracy of the utilization and heat rates of the cogeneration unit(s).

- **Sum of reduction in purchases and sales to the grid**—These two factors may be used as proxies for the information that would have been provided by metered data or reliable engineering estimates. The sum of the two proxies should be equal to the output of the cogeneration system.

  - *Reduction in electricity purchases*. If other actions or project effects do not reduce electricity use in your organization, the reduction in electricity purchases will reflect the output of the cogeneration system. You can use this information to report electricity displaced internal to the plant.

  - *Sales to the utility or other transfers*. Sales of electricity to an electric utility also displace the need for the utility to generate power. This amount can be reported as part of the output of the cogeneration system.

The sum of these two values can be used to compute the displaced central station electricity generation.

Step 3: Apply emissions factors from Appendix B (for fuel input) and Appendix C (for displaced electricity) and sum the effects on emissions. (Alternatively, you can use and document your own emissions factors.) The effect will generally be a reduction in emissions resulting from displaced electricity and an increase resulting from increased fuel input.

Electric utility programs may be involved in your installation of cogeneration units. If a utility or an energy service company is involved in your cogeneration project, you should identify the utility or company in your report. "Involvement" includes any contracts for the purchase of cogenerated electricity from you. (This is reported to help track any multiple reporting of emissions reductions.)

The cogeneration system may represent a significant portion of your operations, and you may have metered data on electricity generation and sales to the grid that you can use in computing your emissions reductions. If you have such metered data, you should use them in preference to engineering estimates. Also, you may be reporting data on cogeneration to the Bureau of the Census or other organizations. If so, you may be able to use these data in computing your emissions reductions. For example, as a cogenerator you already may be filing EIA Form 867, "Annual Nonutility Power Producer Report." Also, data reported to EIA in the MECS include the data necessary to compute reductions in fuel use for cogeneration at the entity-wide level. If you report to the MECS, you may be able to use these data to compute emissions reductions if the cogeneration is your only change that affects energy use.

Example 3.9 illustrates the process of computing net emissions reductions for a cogeneration project.

Example 3.9 - Estimating the Effects of Cogeneration Projects

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A wood products company located in Montana built a 6 MW cogeneration facility adjacent to its sawmill. In the facility, bark and other wood wastes (hog fuel) from the manufacture of lumber were used to fuel a steam boiler. High pressure steam was used to generate electricity, with low pressure steam extracted and sent back to kilns used for lumber drying at the sawmill. Prior to construction of the cogeneration system, steam for the kilns had been produced from wood wastes in a conventional boiler and electricity had been purchased. Excess hog fuel had been burned. The mill operates 8,000 hours per year. The project effects were evaluated relative to a basic reference case that was computed using data for the year prior to the project.

Change in Input Fuel Use

The hog fuel is a biomass fuel source. Because the fuel used did not change, and before the project excess hog fuel was burned, there is no difference between the reference and projected case emissions from hog fuel. In this case, it was not necessary to compute the change (if any) in input fuel use.

Displaced Electricity

The cogeneration facility obtained "qualified facility" status under the Public Utilities Regulatory Policies Act of 1978. Displaced electricity consumption was computed based on the metered output of the cogeneration unit together with information on energy use in the cogeneration facility, sales to the grid, and decreased purchases. For the reference case, the electricity use at the mill was 11 million kWh per year. In the project case, this amount was no longer purchased from the utility. The annual electricity production of the cogeneration unit was 48 million kWh, which left 37 million kWh for potential sale to the grid. However, 4 million kWh/yr of electricity was consumed in the cogeneration facility itself. Also, line losses between the plant and the grid reduced delivered energy by about 5 percent. Thus, the net electricity sold to the grid was 31.4 million kWh per year. Therefore, 42.4 million kWh per year (the sum of the sales and the decreased purchases) of electricity originally generated elsewhere was displaced.

Change in Emissions

Emissions changes were computed for carbon dioxide only; the mill could have chosen to complete the calculations for other gases in Table C.1. Because the company did not have specific information on the emissions factor associated with its purchased and displaced electricity, it used the combined emissions factor for Montana from Appendix C to compute emissions changes.

The net reduction in carbon dioxide emissions due to displaced electricity purchases were computed as follows:

$$42.4\text{x}10^{6}\ \frac{\text{kWh}}{\text{yr}} \bullet 0.777\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MWh}}{1000\ \text{kWh}} = 3.29\text{x}10^{4}\ \frac{\text{ST CO}_2}{\text{year}}$$

Thus, the total net reduction in carbon dioxide emissions was $3.29\text{x}10^4$ short tons per year. In its report, the wood products company identified its action as ARC 2.3.4.1.4 (burn waste to produce steam to drive a steam turbine generator set and use steam exhaust for heat) and identified the utility as a potential reporter.

3.5.6 Estimating Project Effects: Recycling

You may report recycling projects for which you can develop a sound analysis of project effects. The on-site effects of projects that replace virgin raw materials with recycled inputs, such as aluminum scrap and post-consumer recycled aluminum, may be the easiest type of recycling project effects to analyze.

Example: You may be able to compute the difference in the amount of energy required to work with the recycled aluminum versus primary aluminum. Additional effects, such as a possible reduction in primary aluminum production, may be more difficult to analyze, as the production that you no longer require may be sold to another buyer.

Example: Use of coal ash in the production of cement can reduce the amount of carbon dioxide produced, since the volume of carbon dioxide emitted during this process is directly proportional to the lime content of the cement (EIA 1993).[a] Also, cement production uses nearly all of the lime obtained from calcination, so measuring lime content in finished cement is an effective means for determining the amount of carbon dioxide emitted (Griffin 1989, quoted in EIA 1993).

In the United States, most of the structural cement produced is Portland cement, which typically contains 60 to 67 percent of lime by weight (EIA 1993). If you are a cement manufacturer, you can determine the annual carbon dioxide emissions from your production in tons using the following equation:

$$\text{Emissions} = F_l \bullet \frac{44 \text{ g/mole } CO_2}{56.08 \text{ g/mole } CaO} \bullet P$$

where E = annual carbon dioxide emissions, in tons
F_l = lime content of cement, by weight (fraction)
P = annual production of cement, in tons.

This would constitute the reference case for emissions directly from cement manufacture. (Emissions associated with energy used to manufacture cement would be computed as described elsewhere in this document).

If you mix fly ash with cement and sell this mixture in place of 100 percent cement, your project case emissions from production of this mixture would be those associated with manufacturing less

(a) Carbon dioxide is created during the calcination process in which calcium carbonate is heated in a kiln to form lime (calcium oxide). One molecule of calcium carbonate decomposes into one molecule of carbon dioxide and one molecule of calcium oxide. The lime ultimately combines with silicates to form dicalcium or tricalcium silicates, which are two of the four major compounds in powdered cement (EIA 1993).

than 100 percent cement. The emissions reduction would be associated with the amount of cement that did not have to be produced because it was replaced by the fly ash.

You should account for additional project effects where possible, including the shift in sales from you to other manufacturers of 100 percent cement. You may wish to report jointly with the electricity generators who produced the fly ash.

In analyzing recycling projects, your report should be based on sound data and analysis methods and should meet the minimum reporting requirements described in the General Guidelines. In particular, if you report emission reductions associated with diverting waste material from landfills, you should document the studies you relied upon in developing your report.

3.6 Estimating Reductions of Halogenated Substance Emissions

This section provides guidance for reporting reductions in emissions of halogenated substances, which include chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), and other gases. Sections 3.6.1 through 3.6.4 discuss all of these gases as a group; Section 3.6.5 discusses the emission of perfluorocarbons (PFCs) from aluminum production.

Emissions of halogenated substances may be classified into three groups:

Manufacturing Emissions. These arise from spills, leaks, and vents during the manufacture, storage, transport, and transfer of halogenated substances and from the manufacture of other industrial products (primarily aluminum). These emissions include halogenated byproducts released during the production of other halogenated substances.

Immediate Use Emissions. These are related to the use of halogenated substances and occur at the time of use or within one year of use. For example, these emissions result from the use of halogenates as solvent cleaners, pesticides, aerosol propellants, tobacco puffers, sterilants, adhesives, coatings, inks, and blowing agents for open-cell foams.

Delayed Emissions. These emissions result from using, maintaining, and disposing of materials, equipment, and systems that contain halogenates. These emissions occur more than one year after they are incorporated into the materials, equipment and systems. Most delayed emissions are refrigerants used in industrial processes, commercial food storage, motor vehicle air conditioners, and appliances.

Two general categories of emissions-reducing activities are addressed:

- **fugitive emissions reductions**—activities to reduce emissions from the manufacture and use (immediate and delayed) of halogenated substances

- **industrial process emissions reductions**—projects to reduce perfluorocarbon emissions from aluminum production.

Six categories of specific emissions-reducing actions are listed in Table 3.4. You should identify in your report which of these actions you took to reduce your emissions. If you took more than one action, you should identify the appropriate category for each. You should pay careful attention to the reporting restrictions in Table 3.4 regarding Group 1 and Group 2 substances.[a] If your actions are not listed in Table 3.4, you should describe the actions you took. Your report should address separately the individual halogenates that your projects affect.

Table 3.4. Categories of Emissions—Reducing Actions for Halogenates

Process changes. Projects that alter halogenate handling, *in situ* conditions, end-of-the-pipe procedures, equipment, appliance design, and process design and whose objective is to permanently avoid, transform, or otherwise restrict halogenate emissions, excluding capture-and-recovery operations.
Substitution. Projects that reduce immediate-use or delayed emissions by the total replacement of any presently used halogenate with an alternative chemical, technology, or manufacturing process. Emissions resulting from the use of substitutes that are also halogenates should be treated as project effects.
Destruction. Projects that destroy recovered quantities of halogenates consistent with the procedures, technologies, and criteria of relevant EPA rules and international agreements (UNEP 1992), even for projects involving Group 2 substances. Destruction may not be reported to the EPAct Section 1605(b) program if it is used concurrently to obtain Group 1 production or consumption allowances from EPA (40 CFR 82, subpart A).
Recycling and reclamation. Projects that recycle or reclaim recovered halogenated substances, such as the capture and sale of manufacturing emissions or the capture and recycle of halogenated substances from appliances. Where applicable, rules (40 CFR 82, subparts B and F) on recovery and reprocessing should be adhered to.
Leakage control. Projects that minimize annual emission rates and thereby defer emissions from immediate-use or delayed sources through enhanced maintenance, servicing, and equipment that limit leaks, spills, and other types of releases from processes and systems.
Improved appliances. Leakage control projects based on improvements in the design and manufacture of any existing line of halogenate-using appliances that reduce annual emission rates and further delay emissions. Projects that alter the quantity or type of halogenate that an appliance uses or contains would be classified under *process changes* or *substitution* actions, respectively.

(a) This section discusses all halogenated substances as a group. For regulatory purposes, halogenates are divided into two groups: Group 1 comprises gases that deplete stratospheric ozone and are covered by Title VI of the Clean Air Act (40 CFR 82); Group 2 comprises compounds that are not ozone depleters and are often intended as substitutes for Group 1 substances.

Reductions in individual halogenates should be listed separately in your report. Your report could cover multiple sources of emissions and multiple projects to control them, although each emissions-reducing activity should be classified according to Table 3.4.

For a group of similar projects, you may be able to report the number of projects and the total emissions reduction. Although you should retain in your files the detailed calculations used in computing the reduction, you need not report all the technical details on each project. For example, a supermarket chain that reconfigures and refurbishes the system used to charge its refrigeration units may combine the leak reductions for all of its stores, reporting the total emissions reduction and the number of projects.

If you undertake projects that other entities would also be in a position to report, you should identify these potential reporters. For example, entities that destroy emissions that have been recovered by another party should identify the recoverer. If you know that the recoverer is reporting the reductions to the EPAct Section 1605(b) program, you should also provide this information.

3.6.1 Fugitive Emissions Reductions: Establishing the Reference Case

Recall that the reference case is what emissions "would have been" but for the project. In some cases you will be able to use a basic reference case. This will be appropriate for most manufacturing and immediate use emissions. For these emissions, in some cases it may be appropriate to use a reference case modified only to account for production growth or capacity addition (see Section 3.4.1). Your unit of production for the reference case might be the quantity of halogenate produced or quantity of other industrial product or intermediate product produced. You will need to measure emissions per unit production directly or use engineering estimation to arrive at a reference case value.

In the case of delayed emissions, you may need to use a modified reference case. Because virtually 100 percent of the halogenated substances incorporated into materials, systems, and equipment is assumed to be released eventually, you may know precisely the total emissions reduced but will need to determine the likely time frame over which the emissions would have occurred. You will need to indicate this period in your report, even if only simple engineering assumptions are used to compute it. You may then distribute and report the emissions reduction in one of two ways:

1. Determine the total time period over which the emissions would have occurred. Divide emissions by the total number of years in that period and assign that amount to each year.

2. Allocate the reductions according to an engineering model's projected scenario of each year's avoided emissions, summarizing and documenting the modeled projections in your report.

For delayed emissions, then, the reference case is this future emissions path (an equal amount each year or an annual amount determined by engineering models) and the actual project case emissions may be zero (for example, in the case of total destruction). When the project case emissions are zero, computing the reference case emissions gives you the project effects if there are no other project effects that must be considered. You should take care to account for residual emissions in determining whether your project case emissions are zero.

You should indicate in your report which approach you took to developing the reference case for delayed emissions. Your report for future years should indicate that each year's projected reduction did indeed occur (that is, it was not negated by other effects) and you should indicate in the final year that the project has ended.

3.6.2 Fugitive Emissions Reductions: Identifying the Effects of the Project

Recall that your report should identify all the effects of your project. Projects to reduce halogenate emissions are not anticipated to have significant effects on emissions of other (non-halogenate) greenhouse gases. Nevertheless, you should identify and describe potential adverse (or reinforcing) effects on energy consumption or other activities that give rise to greenhouse gas emissions. You should quantify these effects if at all possible.

Some projects that reduce emissions of certain halogenates may affect emissions of *other* halogenates or may affect other emission sources of the same halogenate. You must identify these effects and quantify them if possible.

You should also account for other project effects arising from activity shifting, outsourcing, lifecycle emissions shifting, market effects, and any other sources.

3.6.3 Fugitive Emissions Reductions: Estimation Methods

Compared with other types of greenhouse gas emissions, halogenate emissions often lack straightforward emission factors that are widely applicable. Where they exist, such factors tend to be project specific and require that you use engineering estimates, analyses of chemical balances, direct monitoring, or empirical averages of halogenate losses in your calculations.

As was the case for energy-related emissions, only two methods are applicable for estimating halogenate emissions: direct measurement and engineering estimation. No default values (emissions factors or stipulated factors) are available.

Direct Measurement. For projects involving the extraction or containment of halogenated substances for subsequent destruction, recycling, or reclamation, direct measurements based on chemical tests or on the amount held in standard containers offer a straightforward way to determine reportable quantities. You must ensure that reported quantities are not significantly biased due to the presence of other matter (for example, lubricants) with the recovered halogenate. Direct measurement may also prove feasible or even necessary (at least intermittently) for determining emissions exhaust rates or the effectiveness of destruction operations. For destruction that is 98 percent or more effective, you can assume that the halogenated substance in question is completely destroyed.

Engineering Estimation. For a variety of projects—especially ones involving leakage control and process changes—engineering calculations, stoichiometric analyses, averaged or assumed rates of leakage, and other approaches may be important methods for estimating total reductions of halogenate emissions or useful emission factors.

3.6.4 Fugitive Emissions Reductions: Data Sources and Examples

In many cases, you can report or verify data on key activities or actual emissions using data that you may already report to the EPA. Because the Clean Air Act (CAA) and other statutes govern the production, consumption, handling, and substitution of Group 1 halogenates, the rules and technical information that EPA has issued may offer guidance for compiling data and reporting under the EPAct Section 1605(b) program. These rules and technical information include the following:

- **EPA's Toxic Release Inventory** contains publicly available information concerning chemical releases, off-site treatment and disposal, recycling, energy recovery, on-site treatment, and pollution prevention activities at manufacturing facilities throughout the United States. Known stratospheric ozone depleters are one of the groups of chemicals specified in the inventory.

- **Sections 603, 608, 609, and 612 of the CAA, and proposed rules under Section 112 of the Act** contain requirements for record keeping, reporting, handling, disposal, recovery, recycling, and reclamation of ozone depleters and refrigerants and stipulate safe, legally acceptable substitutes for Group 1 substances due to be banned.

These government activities as well as initiatives in the private sector and Action #40 of the Climate Change Action Plan (October 1993) may also provide important technical factors that can be used or adapted for estimating halogenate emissions reductions.

The following four examples illustrate how to estimate emission reductions for projects involving fugitive emissions.

Example 3.10 - Fugitive Halogenate Emissions Reductions Resulting From Process Changes

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

An insulation manufacturer purchased "X" pounds of a particular halogenated substance. Adoption of an alternative manufacturing process resulted in a decrease in the quantity of the halogenate required per board foot of insulation, such that only "Y" pounds must be purchased each year. The halogenate incorporated in the insulation was assumed to eventually be completely released (delayed emissions). Also, some of the purchased halogenate may have leaked out at the time of use.

The manufacturer can report an annual emissions reduction of "X" minus "Y" after accounting for the time period over which the emissions would have occurred. (If production of insulation varied from year to year and especially if it was trending upwards, the manufacturer might have preferred to calculate emissions based on units of production and the quantity needed per board foot of insulation.) The reporting entity may have chosen to report an annual emissions reduction (over the time period over which emissions would have occurred) based on a modeled scenario of releases over time or may have divided the total emissions reduction by the number of years over which it would have been emitted and reported that amount each year.

Example 3.11 - Fugitive Halogenate Emissions Reductions Resulting From Substitution

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

As part of a program to decrease the effects of its operations on global warming, a manufacturer of open-cell foam switched from CFC-11 to HFC-134a as a blowing agent. The amount of HFC-134a required for the same level of production was 110 percent of the amount of CFC-11 needed.

This manufacturing activity was assumed to generate only immediate use emissions. Using a basic reference case in the year before the project, the manufacturer reported as its emissions reduction the amount of CFC-11 that was used and emitted in the reference year. (The project case emissions of this CFC-11 were zero.) However, HFC-134a is also a halogenated substance and the manufacturer knew that its emissions must be accounted for. Thus, its report to the EPAct Section 1605(b) program identified the amount of each gas (CFC-11 and HFC-134a) emitted in both the reference and project cases. The report identified the category of emissions-reducing action (from Table 3.4) as "substitution."

Example 3.12 - Fugitive Halogenate Emissions Reductions Resulting From Improved Appliances

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A maker of residential refrigerators developed an improved model that, based on empirical tests and engineering estimates, emitted less per year of a certain halogenate than did the previous versions. The refrigerator manufacturer reported the emissions reduction per unit sold and the number of units sold per year, and reported each year's sales and emissions reductions in subsequent years. To track multiple reporting, the manufacturer identified consumers as potential additional reporters of these reductions.

Example 3.13 - Fugitive Halogenate Emissions Reductions Resulting From Recycling and Reclamation

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A municipality or utility instituted and contracted for an appliance pickup program or special processing stations at local landfills or scrap yards to remove refrigerants from household and commercial devices. The municipality or utility reported the yearly total of each halogenate that is recovered and recycled or reclaimed for sale. The emissions reduction report indicated the time period over which each reported halogenate would have eventually been released. In this case, for each halogenate, the time period is an average of assumed leakage profiles for the many types and vintages of equipment that had been processed. For each gas, the municipality or utility may have elected to allocate the emissions reductions evenly over the time period. Alternatively, if the majority of emissions would have been concentrated in future years of the time period, the municipality or utility may have wished to use an appropriate engineering model to determine the emissions profile and registered annual reductions accordingly.

3.6.5 Industrial Process Emissions from Aluminum Production

Industrial process emissions of halogenated substances arise as byproducts of the manufacture of another substance (that is, other than halogenates). An important emissions source is aluminum production, which results in emissions of perfluorocarbons (PFCs). Detailed guidance is provided here for this source. If you have other industrial processes that emit halogenated substances as byproducts, you may report so long as your report meets the standards for good project analysis discussed in the General Guidelines and this supporting document.

The production of aluminum results in emissions of several greenhouse gases, including carbon dioxide and two PFCs, CF_4, and C_2F_6. Carbon dioxide emissions are primarily the result of energy use (typically electricity); guidelines for reporting carbon dioxide emissions and emissions reductions are provided earlier in this chapter. Emissions of the two perfluorocarbons occur as a result of anode effects during the reduction of alumina in the primary smelting process. Details on the processes that give rise to these emissions, the practices for reducing them, and related regulations and programs may be found in Appendix 3.B. The remainder of this section provides specific guidance on reporting PFC emissions and emissions reductions.

Emissions reductions activities will primarily involve operational and management changes that reduce the frequency and duration of anode effects. For example, the frequency of these effects can be reduced by incremental improvements in (1) managing alumina additions and other process parameters, (2) algorithms controlling automated processes, (3) training of personnel, and (4) quality control of anode manufacture to reduce subsequent carbon dust formation. The average duration of anode effects can be reduced by improving the suppression response of potroom[a] personnel.

Establishing the Reference Case

Your report should describe the specific activities you undertook to reduce PFC emissions. You may choose a basic or a modified reference case for your report (see the definitions in the General Guidelines and Section 3.4 of this supporting document), which may cover all or a portion of your facility. While the primary effect of the project will be to reduce PFC emissions, you should describe and compute any other effects on energy use and associated carbon dioxide emissions.

Estimating Emissions

The calculation methodology presented here includes some default emissions factors. You are encouraged, however, to base your estimates on actual emissions measurements for your facility. Measurement protocols will be defined in the future as part of EPA's voluntary program with the aluminum industry to reduce emissions (see Appendix 3.B). When available, these protocols will improve the accuracy of default emission factors.

The methodology described here calculates PFC emissions per unit production of aluminum as a function of several operating variables. These operating variables are altered as a result of the emissions-reducing activities you undertake. Total annual emissions and emissions reductions are then calculated based on reported annual production levels, which, in turn, are based on physical measures of output. The key variables used are the frequency (anode effects per day) and duration (minutes per effect) of the anode effects.[b] If possible you should monitor these variables (preferably on a continuous basis) and use your facility-specific data in the calculations.

(a) The potroom is the room containing the electrolytic cells used to produce primary aluminum from alumina.

(b) The reported anode effect duration depends on the exact definition of an anode effect. Definitions may vary somewhat, depending, for example, on the voltage level used to define the start and end of the anode effect. Your report should carefully describe the definitions you used in developing your estimates.

You can use the following equation to compute emissions of CF_4 per unit production:

$$X\left(\frac{\text{kg } CF_4}{\text{MT Al}}\right) = A\left(\frac{\text{kg } CF_4 \text{ / AE min}}{\text{kAmp}}\right) \bullet B\left(\frac{\text{AE min}}{\text{AE}}\right) \bullet C\left(\frac{\text{AE}}{\text{day}}\right) \bullet \left(\frac{1}{\text{CE}}\right) \bullet 124.2\left(\frac{\text{kAmp days}}{\text{MT Al}}\right)$$

where X = the kg of CF_4 emitted per metric ton of aluminum production
A = the kg of CF_4 emitted during each minute of an anode effect, per kAmp of current
B = the average duration of anode effects, expressed in anode effect minutes per effect
C = the average frequency of anode effects, expressed in anode effects per day
1/CE = the inverse of the current efficiency for aluminum smelting
124.2 = the electric current required to produce a metric ton of aluminum, assuming 100 percent efficiency, in kAmp days per metric ton of aluminum.

You should use facility-specific data for the emissions factors A and B. Your report should include the values you used for *C* (anode effects per day), CE (current efficiency), A, and B.

The emissions factor for C_2F_6 currently is estimated to be an order of magnitude lower than that for CF_4. Therefore, the emission calculation methodology for C_2F_6 is as follows:

$$Y\left(\frac{\text{kg } C_2F_6}{\text{MT Al}}\right) = 0.1 \bullet X\left(\frac{\text{kg } CF_4}{\text{MT Al}}\right)$$

3.7 Estimating Methane Emissions Reductions from Natural Gas Systems

The U.S. natural gas system comprises a complex interconnected set of facilities that include production facilities, gas production facilities, transmission pipelines, storage and injection/withdrawal facilities, and distribution systems. Methane is the principal component of natural gas; therefore, leaks from the wide variety of components, processes, and activities that make up the natural gas system contribute to methane emissions. This section provides technical guidance on estimating emissions and emissions reductions from natural gas systems. Details on the U.S. natural gas system, total U.S. methane emissions from this system, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.C.

Methane emissions from the natural gas system can be classified into three groups:

- **normal operations**, including compressor engine exhaust emissions, emissions from pneumatic devices, and fugitive emissions (small chronic leaks from components that store or convey gas)

- **routine maintenance**, including equipment blowdown and venting, well workovers, and scraper (pigging) operations

- **system upsets** including emissions due to sudden, unplanned pressure changes or mishaps.

You may report reductions of these emissions if you are a legal entity that controls a natural gas system and you undertake emission reduction projects. Typical reporting entities could be gas distribution companies, gas transmission companies, integrated gas companies (both transmission and distribution), combination utilities (gas and other utilities, such as electricity and water), and production companies. You may choose to report your emissions reductions through a third party, such as a trade association.

If you currently report information about your system under existing safety and other regulatory programs, you may wish to make use of this information in estimating your emissions and emissions reductions. You may be able to take advantage of the emission reduction estimating techniques and reporting system developed under the EPA's Natural Gas STAR program in developing your EPAct Section 1605(b) report.

In some cases oil and gas resources are owned by one party (or group of parties), and a second party is responsible for withdrawing and marketing the resource. A typical example is an oil and gas company running a production field in which there are a variety of property owners. The company pays the property owners royalties based on the amount of oil and gas produced and marketed. In this case, the company running the field may be in the best position to estimate emissions reductions and could be the reporting entity, unless contractual arrangements among the parties specify otherwise.

A reporting entity may report separately for its individual operating units. For example, an integrated company may report separately for its distribution system and its transmission system. A distribution system may decide to submit separate reports for individual operating districts within the overall distribution system. Similarly, a production company may decide to report separately for each production field, possibly reporting separately for its production well/gathering pipeline unit and its gas processing plant. While there is flexibility in defining the scope of the report, the report should reflect the full extent of the projects undertaken to reduce emissions.

You should describe the equipment upgrade, change in operating or maintenance practice, or other action(s) you took to reduce emissions. You should describe in physical terms the number of projects or the amount of the gas system to which your project applies—for example, miles of pipeline, number of valves, or number of compressor stations. If you currently report projects you have undertaken (not just committed to undertake) to the Natural Gas STAR program, you could use that information as a basis for preparing your EPAct Section 1605(b) report.

Activities to reduce methane emissions in natural gas systems include the following:

- replacing high-bleed pneumatic devices with low- or no-bleed designs

- recovering methane from gas dehydrators and using it for fuel in glycol regeneration boilers

- implementing directed inspection and maintenance programs to reduce fugitive emissions from seals, valves, fittings, assemblies, corroded pipeline, and gate stations

- replacing or repairing leaking subsurface pipeline

- replacing reciprocating engines with turbine engines for compression

- installing catalytic converters on reciprocating engines

- using portable evacuation compressors (rather than venting) to remove gas from sections of pipe to be repaired

- using "smart" regulators in distribution systems

- using metallic coated seals

- using sealant and cleaner injections in valves

- using composite wraps in pipeline repair.

At this time, you may report methane emissions reductions achieved by any means. These include direct reductions at the point of end use achieved by reducing gas demand—that is, demand-side management (DSM) activities. It will be difficult to develop a credible report of indirect emissions reductions (that is, from the natural gas system) resulting from DSM activities. This is because gas system methane emissions are not a simple function of gas throughput or deliveries. If you report such reductions you should document the basis for your estimates in your report.

3.7.1 Establishing the Reference Case

The reference case should encompass the portion of the gas system affected by the emission reduction project. For natural gas systems, methane is often the only greenhouse gas affected by a project. However, in cases where projects involve changes in combustion requirements (for example, for compressor engines) or substitution of electric devices for gas-pressure driven devices, the implications for carbon dioxide emissions must also be considered. In these situations the reference case should include both carbon dioxide and methane emissions.

3.7.2 Identifying the Effects of the Project

You must identify the effects of your project, including potential impacts on other portions of your system and outside the system. In some cases, the project may affect parts of the natural gas system that are not directly under the influence of the project. If these impacts affect emissions, these effects should be identified and should be quantified whenever possible.

Generally, for the natural gas system itself, shifting of emissions from one activity to another is not a significant problem because the system facilities themselves must be maintained and operated to keep the system running.

3.7.3 Estimating Emissions

To estimate reference case and project case emissions from natural gas systems, you will need to characterize your system components and practices, select or estimate emissions factors, and apply the emissions factors to the system characterization. A system characterization consists of the following:

- Define each type of component that contributes to the emissions being included in the reference case.

- Count or estimate the number of components.

- Define each operating practice that contributes to emissions being included in the reference case.

- Count or estimate the frequency with which the operating practices are undertaken.

These data may be obtained through system inspections and surveys and by reviewing operating reports. Because natural gas systems are often very large and complex, it may be appropriate to focus this effort only on those emissions sources that are affected by the emissions-reducing projects. For example, if the project only affects fugitive emissions at distribution system pressure regulating facilities, you may wish to characterize only these facilities. In some cases, the characterization must be made based on assessments of what the components or practices would have been had the project not been undertaken (the modified reference case).

Once the system is characterized, emission factors for the components and practices are needed. If possible, you should measure emissions from a representative set of components or operating events to obtain system-specific emissions factors. If these are not available, emissions factor estimates based on previous studies can be used, or engineering estimation may be used to develop emissions factors.

Finally, the emissions factors should be applied to the system characterization to estimate emissions. This process would be replicated for each emissions type and greenhouse gas affected by the project.

An alternative to the approach described above is to measure or estimate emissions reductions directly. The preferred basis for estimating emissions reductions is actual field measurements. Examples of measurement approaches include the following:

Fugitive Emissions. For projects that reduce fugitive methane emissions (that is, leaks), changes in the number of leaks and the average leak rate could be measured. The number of leaks could be measured using equipment that detects methane, such as an organic vapor analyzer. Standard methods for detecting leaks have been developed by the EPA and are used in various state inspection and maintenance programs. Leak rates could be measured by isolating leaks and conducting mass flow measurements. Alternatively, the leak rate could be assumed to remain unchanged, so that only the change in leak frequency contributes to emissions reductions.

Pneumatic Devices. For projects that reduce emissions by replacing high-bleed pneumatic devices with low-bleed devices, the emissions from each type of device can be measured as the volume of gas released when the device is actuated multiplied by the frequency of activation. Activation frequency can be measured by observing the device in operation. The volume released can be estimated from the gas pressure and the device size.

Engine Exhaust. For projects that reduce methane emissions in engine exhaust by substituting turbine engines for reciprocating engines, the emission reduction can be estimated by measuring the methane in the exhaust per unit of fuel from each engine and multiplying by the fuel that each engine would use. Carbon dioxide emissions would also be calculated based on fuel use using the emissions factors in Appendix B.

While these techniques can be used to measure emissions and emissions reductions directly, it is often costly to do so. If direct measurement is not feasible, stipulated factors can be used for estimating emissions reductions for specific projects that have been well defined and evaluated. The EPA Natural Gas STAR program has developed such factors, which are listed in Table 3.5. To apply these factors, you should characterize your project in terms of the units listed in the table. For emissions factors that you estimate for your system, you should state the basis for your estimation in your report. You should describe carefully the basis for any emissions reduction factors you estimate that exceed the values in Table 3.5.

Table 3.5 Stipulated Emissions Reduction Factors for Natural Gas Systems

Emissions Reduction Project	Units for Measuring the Extent of the Project	Emission Reduction per Unit
Directed inspection/maintenance program at compressor stations[a]	Number of compressor stations	8.54 million cf/yr per compressor station
Directed inspection/maintenance program at city gate stations[b]	Number of gate stations	1.19 million cf/yr per gate station
Replace high-bleed pneumatic devices at transmission facilities	Number of devices replaced	70 thousand cf/yr per device[c]
Directed inspection/maintenance program at production facilities	Number of wellsites[d]	31.5 thousand cf/yr per wellsite
Replace high-bleed pneumatic devices at production facilities	Number of devices replaced	70 thousand cf/yr per device[c]
Recover gas vented during pipeline blowdowns	Per blowdown	Estimated on a case-specific basis[e]
Recover emissions from dehydrator using a flash tank separator	Number of flask tank separator/gas recovery units installed	0.15 thousand cf/million cf of gas throughput plus 90 percent of the gas used to drive the glycol circulation pump[f]
Use turbines instead of reciprocating engines	Per substitution	Estimated on a case-specific basis[g]

(a) Compressor station includes the compressor engines and all other associated components used to maintain gas pressure in transmission pipelines.
(b) Gate station includes all components at the surface facility.
(c) Emissions per device vary by device size and type. Reported value is an average.
(d) Wellsite includes the gas wellhead and associated treatment facility equipment such as heaters, gas/liquid separators, and dehydrators.
(e) Emissions from blowdowns are estimated on a case-specific basis. Emissions reductions from the use of portable evacuation compressors can be estimated at 80 percent of the gas released per blowdown.
(f) Gas may be used to drive the glycol circulation pump. Gas use and emissions from the pump are on the order of 0.8 thousand cf/million cf of gas throughput, 90 percent of which can be recovered using the flash tank separator. Estimates must also be adjusted for the methane portion of the gas (for example, 90 percent on a volume basis).
(g) Reciprocating engines emit 0.510 metric tons per million cf of fuel use; turbines emit 0.009 metric tons/million cf of fuel use. Emissions reductions resulting from the use of turbines instead of reciprocating engines are determined on a case-specific basis after estimating the change in fuel use.

Note: Only directed inspection/maintenance programs at compressor stations and city gate stations have been formally adopted by the National Gas STAR program as cost effective for all participants. The cost effectiveness of other practices is determined on a case-by-case basis.

Source: EPA Natural Gas STAR Program.

3.8 Estimating Methane Emissions Reductions from Landfills

Methane is produced in municipal solid waste landfills when organic matter in the refuse is decomposed by bacteria under anaerobic conditions. Landfills are the largest anthropogenic source of methane emissions in the United States. This section provides technical guidance on estimating emissions and emissions reductions from landfills. Details on total U.S. methane emissions from landfills, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.D.

Entities can reduce methane emissions from landfills through two general approaches: modifying waste management practices to reduce the amount of waste landfilled, and recovering the methane and using it as an energy source or flaring it. Using or flaring recovered methane in the only method currently available for reducing emissions from current landfills and from landfills that will contain degradable waste in the future. Recovered gas can be used to generate electricity or can be sold as a medium-Btu fuel to fire industrial boilers, chillers, or similar equipment. Technologies and processes under development to use landfill gas include fuel cells and the production of liquid fuels and industrial chemicals.

You may report reductions of landfill methane emissions if you own the landfill and you undertake emissions reductions projects, or if you contract with a third party to collect and market the recovered gas. In the latter case, you may wish to agree on which party will report the reductions; the report should indicate the other party as a potential reporter, to track possible multiple reporting.

Your report should describe the amount of the landfill (surface area and the waste in place) that are under the influence of the landfill gas collection system and the specific activities you undertook to reduce emissions.

3.8.1 Establishing the Reference Case

No reliable method exists to estimate the amount of methane emissions that would have been emitted from a landfill in the absence of emissions-reducing projects. Therefore, a reference case will not be required for landfill emissions reduction projects. Your emissions reductions can be estimated directly as the amount of methane you recover.

3.8.2 Estimating Emissions Reductions

The most accurate basis for estimating emissions reductions is actual field measurements. You can use the measured amount of landfill gas that is recovered from the landfill and utilized (that is, combusted on-site or sold for combustion off-site) as the estimate of the emissions reduced.

In addition to measuring the volume of gas produced, you must also monitor the methane concentration in the gas. To determine the avoided methane emissions, you must correct the total volume of gas produced based on measured methane concentrations. For example, if you recover 1 billion cubic feet of gas (based on metered flow) with a methane concentration of 50 percent in air, your reportable avoided emissions are 1 billion x 0.5 = .5 billion cubic feet (on a 100 percent methane basis).

In some cases, direct measurements of methane recovery will be unavailable and it may be necessary for you to make engineering estimates of the recovery volume. Possible projects where engineering estimates could be employed include the use of methane at the landfill site for power generation or as fuel in co-located facilities.

Engineering estimates of methane emissions avoided should be determined based on the fuel requirements of the project's methane utilization option. For example, if methane recovered from the landfill is being used in an on-site turbine, an engineering estimate could be prepared by using data on the electricity output of the turbine and the efficiency of the generator. This information would enable you to estimate the fuel input into the turbine, which would represent avoided methane emissions.

The amount of methane recovered is an overestimate of actual methane emissions reduced because in the absence of the gas recovery system, a portion of the methane produced in the landfill would be oxidized as it migrates out of the landfill. Withdrawing the gas with a collection system prevents this oxidation step. The extent of oxidation that will occur depends on local conditions and is not well defined. Because no single oxidation adjustment factor is available at this time, the amount of gas collected and utilized should be used as the estimate of emissions reduced. That is, a default value of zero will be used for the oxidation factor. However, if you have site-specific information that allows you to compute an oxidation factor for your landfill, you should use this value rather than the default value.

While no stipulated emission reduction values are available for landfill methane emissions, you should use the following guidelines in determining whether your estimated emissions reduction falls within the expected range:

- Total emissions can be reduced by up to 85 percent

- In nearly all cases, emissions reductions are expected to be less than 6 kg of methanol per ton of refuse in the landfill. Most emissions reductions will be well below this figure.[a]

If your estimated emissions reduction exceeds these values, your report should provide a full description of the basis for your estimate.

(a) This upper bound estimate is based on a maximum estimate of about 16 m^3/min of methane per million metric tons of refuse. This maximum is about 100 percent larger than the average emissions factor for non-arid landfills reported in EPA 1993a.

3.9 Estimating Methane Emissions Reductions from Coal Mines

Methane and coal are formed together during coalification, a process in which ancient biomass is converted into coal by biological and geological forces. Methane is stored in coal seams and within surrounding rock and released when coalbed pressure is reduced through natural erosion, faulting, or mining. This section provides technical guidance on estimating emissions and emissions reductions from coal mines. Details on total U.S. coal mining emissions, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.E.

The major approaches for recovering and using coal mine methane are as follows (see Appendix 3.D for more detailed descriptions):

- **Gob Wells**. Gob wells are drilled from the surface to a point just above the coal seam. As mining advances under the well, the methane-charged coal and strata around the well fractures. The methane emitted from this fractured area flows into the gob well and up to the surface. Initially, gob wells produce nearly pure methane. Over time, however, ventilation air from mine working areas may flow into the gob area and dilute the methane.

- **In-mine Horizontal Boreholes**. In-mine boreholes are drilled inside the mine (as opposed to from the surface), and they operate to drain methane from unmined areas of the coal seam shortly before mining. The recovery efficiency of this technique is low—approximately 10 to 20 percent of methane that would otherwise be emitted. However, the methane produced is typically over 95 percent pure.

- **Advance (Pre-Mining) Degasification**. With this method, vertical wells are drilled into the coal seams several years in advance of mining. Depending on the length of time that the wells are in place, the majority of the methane that would otherwise be emitted to the atmosphere when the coal was extracted can be recovered before mining begins. An advantage of this recovery method is that a nearly pure methane can be recovered. A disadvantage of this method is that it may be difficult for some mines to plan where they will mine many years in advance of the actual mining.

Options for utilizing recovered methane include injecting (nearly pure) methane into a pipeline, using methane (which can be mixed with ventilation air) as a fuel in an on-site generator, co-firing methane in a nearby boiler, and selling low Btu gas (methane mixed with mine air) to nearby industrial users. Emerging technologies and practices for reducing methane emissions from coal mining include technologies for separating methane from carbon dioxide, oxygen, and/or nitrogen and technologies to use ventilation air as the combustion fuel for on-site turbines or boilers.

You may report reductions of coal mining emissions if you are a legal entity that controls a coal mine(s) and you undertake emissions reduction processes. The coal mining company would have the most accurate information about measures taken to reduce emissions and their effects. A third party could contract to withdraw and market the coalbed methane; in this case, the report should identify the other party as a potential reporter, to track multiple reporting.

You may report separately for your individual operating units (for example, coal mines) or you may combine all your projects into a single report, taking care to account for all potential project effects within and outside of your organization. You may report emissions reductions resulting from reducing the quantity of coal produced or from reducing production at a gassy mine in favor of increasing production at a less gassy mine. However, if you report such reductions, you should provide documentation of the production shifts in your report and identify whether the production you reduced may have been offset by increased production by another entity.

3.9.1 Establishing the Reference Case

The reference case is complicated by the potential for pre-mining gasification as much as 10 years before mining begins and by the potential for poor quality of emissions estimates. In some cases, the precision of the reference case emissions estimates is much poorer than the precision of the emissions reduction estimates. For these reasons, a reference case will not be established as a separate step; rather, the quantity of recovered gas will be used to estimate emissions reductions directly.

3.9.2 Estimating Emissions Reductions

The method for determining emissions reductions depends on whether methane is recovered during or prior to mining.

- **Methane Recovery During Mining**. The quantity of methane recovered each year from gob wells or horizontal boreholes would be the reportable emissions reduction for that year, corrected to account for methane content (see below).

- **Pre-Mining Degasification**. When methane is recovered in advance of mining, the recovery generally occurs several years before the methane would have been emitted. As the coalbed is mined through, each year you should estimate the emissions reduction associated with the amount of coal mined that year, and report that amount to the EPAct Section 1605(b) program.

In many cases, direct measurements of methane recovery may be available at various points in the gas collection and/or treatment system. (However, in some cases actual measurements will not be available and engineering estimates must be used.) Possible sources of direct measurements include the following:

- **At the wellhead**—Many mines will monitor methane production from each well or block of wells within a particular mining section to assess the effectiveness of the methane drainage program and optimize methane recovery. If the produced gas is used, direct measurements taken at the point of production are an accurate means of determining avoided emissions.

- **At point of compression or treatment**—Depending on the type of utilization, it may be necessary to treat and/or compress the methane recovered by the mine. Where methane is injected into pipelines, for example, gas must be cleaned and compressed to meet pipeline specifications. Measurements may be taken by the gas producer at various points in these systems.

- **At the point of sale**—If the recovered methane is sold, measurements will likely be made at the point of sale.

In addition to measuring the volume of gas produced, you must also monitor the methane concentration in the gas. (See the discussion in Section 3.8.) Measurements of methane concentrations (that is, gas quality) are readily available for most methane utilization projects at coal mines. Where gas is being sold to pipelines, for example, mines must continuously monitor gas composition to ensure that pipeline specifications are met. For other gas uses, measurements of gas composition may also be taken to ensure that the specifications of the gas user are met. Finally, for those methane recovery technologies employed in close conjunction with mining (that is, gob wells or in-mine drainage systems), the Mining Safety and Health Administration requires monitoring of the operating methane recovery system to ensure that methane concentrations do not drop into the explosive zone.

While no stipulated emission reduction values are available for coal mine methane emissions, you should use the following guidelines in determining whether your estimated emissions reduction falls within the expected range:

- Total emissions can be reduced by up to 70 percent

- In nearly all cases, emissions reductions are expected to be less than 60 kg of methane per ton of coal mined; most emissions reductions would be less than 30 kg of methane per ton of coal mined.[a]

If your estimated emissions reduction exceeds these values, your report should provide a full description of the basis for your estimate.

3.10 Estimating Reductions of Nitrous Oxide Emissions from Adipic Acid Plants

Nitrous oxide is produced as a waste gas during the production of adipic acid, which is used primarily in the manufacture of nylon. The production of nitric acid, an input to the adipic acid production proc-

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(a) The upper figure is estimated assuming that 70 percent of the emissions are recovered from a coal mine with methane emissions of 4,000 ft^3 per ton of coal mined. Only a small number of mines in the U.S. have a gas content this high. Most U.S. mines have methane emissions of less than 2,000 ft^3 per ton of coal mined, which was used to estimate the lower value.

ess, also produces nitrous oxide emissions. This section provides technical guidance on estimating emissions and emissions reductions from adipic acid plants; you can use the same guidance to report emissions reductions from nitric acid production. Details on the adipic acid industry, its emissions, and related regulations and programs may be found in Appendix 3.F.

Nitrous oxide (N_2O) emissions from adipic acid plants can be reduced by collecting or destroying the gas. Although thermal decomposition of N_2O is effective, its energy requirements are substantial. In addition, it produces NO_x emissions, which are also undesirable. Other promising alternatives being investigated by adipic acid manufacturers include conversion of N_2O to NO for recovery/reuse in the nitric acid production process; and catalytic decomposition of N_2O to N_2, O_2, and a small amount of residual NO_x.

You may report reductions of nitrous oxide emissions if you undertake projects to reduce emissions at adipic acid or other plants. You may report for a collection of plants, a single plant, or a portion of a plant, taking care to account for all potential project effects within and outside your organization.

3.10.1 Establishing the Reference Case

You may choose a basic or modified reference case as defined in the General Guidelines. The year you choose for a basic reference case should be indicative of normal operations. Nitrous oxide would be reported as the principal greenhouse gas affected by your project. However, in cases where projects involve changes in combustion requirements or electricity purchases, you must also consider the implications for carbon dioxide emissions. In this case, the reference case should include both carbon dioxide and nitrous oxide.

3.10.2 Estimating Emissions Reductions

While extensive emissions data have not been published, it appears that nitrous oxide emissions measurement does not pose significant difficulties. You could estimate reference case and project case emissions using stoichiometric models and verify the estimates through field measurements. You could then use the validated models to estimate emissions.

3.11 Bibliography

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Appendix 3.A

Assessment Recommendation Codes

Assessment Recommendation Codes

The Assessment Recommendation Codes are taken from the U.S. Department of Energy's Energy Analysis and Diagnostic Center program, which provides energy and waste-minimization audits to small and medium-sized companies. You should indicate the appropriate ARC or ARCs for your project in your report. If your project is not adequately described in the ARC list, you should describe the project clearly in your report. You are not limited to reporting projects contained in the ARC list.

2. Energy Management

2.1 Combustion Systems

2.1.1 Furnaces, Ovens and Directly Fired Operations

2.1.1.1 Operational Improvements
- 2.1.1.1.1 Control Pressure on Steamer Operations
- 2.1.1.1.2 Heat Oil to Proper temperature for Good Atomization
- 2.1.1.1.3 Reduce Combustion Air Flow to Optimum
- 2.1.1.1.4 Limit and Control Secondary Combustion Air in Furnace Operations to the Amount Required for Proper Furnace Operation
- 2.1.1.1.5 Eliminate Combustible Gas in Flue Gas
- 2.1.1.1.6 Improve Combustion Control Capability

2.1.1.2 Hardware
- 2.1.1.2.1 Use Soft Insulation in Cycling Furnaces to Facilitate Heating Up and Cooling Down
- 2.1.1.2.2 Resize Charging Openings or Add a Movable Door on Fuel-Fired Equipment
- 2.1.1.2.3 Install Automatic Stack Damper

2.1.1.3 Maintenance
- 2.1.1.3.1 Repair Faulty Insulation in Furnaces, Boilers, etc.
- 2.1.1.3.2 Repair Faulty Louvers and Dampers
- 2.1.1.3.3 Adjust Burners for Efficient Operation
- 2.1.1.3.4 Eliminate Leaks in Combustible Gas Lines
- 2.1.1.3.5 Repair Furnaces and Oven Doors So That They Seal Efficiently

2.1.2 Boilers

2.1.2.1 Operation
- 2.1.2.1.1 Move Boiler to More Efficient Location
- 2.1.2.1.2 Operate Boilers on High Fire Setting
- 2.1.2.1.3 Direct Warmest Air to Combustion Intake

2.1.2.2 Hardware
- 2.1.2.2.1 Replace Obsolete Burners with More Efficient Ones
- 2.1.2.2.2 Install Turbulators
- 2.1.2.2.3 Install Smaller Boiler (Increase High Fire Duty Cycle)
- 2.1.2.2.4 Replace Boiler

2.1.2.3 Maintenance
- 2.1.2.3.1 Establish Burner Maintenance Schedule for Boilers
- 2.1.2.3.2 Keep Boiler Tubes Clean
- 2.1.2.3.3 Analyze Flue Gas for Proper Air/Fuel Ratio

2.1.2.4 Blowdown
- 2.1.2.4.1 Reduce Excessive Boiler Blowdown
- 2.1.2.4.2 Minimize Boiler Blowdown with Better Feedwater Treatment
- 2.1.2.4.3 Use Heat From Boiler Blowdown to Preheat Boiler Feed Water

2.1.3. Combustion of Waste Products

2.1.3.1 General
- 2.1.3.1.1 Burn Waste Paper for Heat
- 2.1.3.1.2 Install Solid Waste Incinerator for Heat
- 2.1.3.1.3 Burn Wood By-Products for Heat
- 2.1.3.1.4 Burn Waste Oil for Heat

2.1.4 Convert to More Efficient Fuel

2.1.4.1 Electric to Fossil Fuel
- 2.1.4.1.1 Replace Electrically-Operated Equipment with Fossil Fuel Equipment

2.1.4.2 Fossil Fuel to Electric
- 2.1.4.2.1 Replace Fossil Fuel Burning Equipment with Electrical Equipment
- 2.1.4.2.2 Use Electric Heat in Place of Fossil Fuel Heating System
- 2.1.4.2.3 Replace Gasfired Absorption Air Conditioners with Electric Units

2.1.4.3 Alternate Fossil Fuel
- 2.1.4.3.1 Burn a Less Expensive Grade of Fuel
- 2.1.4.3.2 Convert Combustion Equipment to Burn Natural Gas
- 2.1.4.3.3 Convert Combustion Equipment to Burn Oil
- 2.1.4.3.4 Convert Oil or Gas Burners to Combustion of Coal
- 2.1.4.3.5 Replace Gasoline with Diesel, LPG, or Natural Gas

2.1.4.4 Other
- 2.1.4.4.1 Replace Purchased Steam with Electric Heating
- 2.1.4.4.2 Replace Purchased Steam with Other Energy Source
- 2.1.4.4.3 Use Steam Sparging or Injections in Place of Indirect Heating
- 2.1.4.4.4 Replace Steam Jets on Vacuum System with Electric Motor Driven Vacuum Pumps

2.2 Thermal Systems

2.2.1 Steam

2.2.1.1 Traps
- 2.2.1.1.1 Install Steam Trap
- 2.2.1.1.2 Use Correct Size Steam Traps
- 2.2.1.1.3 Repair or Replace Steam Traps
- 2.2.1.1.4 Shut Off Steam Traps on Super Heated Steam Lines When Not in Use

2.2.1.2 Condensate
- 2.2.1.2.1 Increase Amount of Condensate Returned
- 2.2.1.2.2 Cover Condensate Storage Tanks
- 2.2.1.2.3 Insulate Condensate Lines
- 2.2.1.2.4 Insulate Feedwater Tank
- 2.2.1.2.5 Repair Insulation on Condensate Lines
- 2.2.1.2.6 Install De-Aerator in Place of Condensate Tank
- 2.2.1.2.7 Replace Barometric Condensers with Surface Condensers
- 2.2.1.2.8 Return Steam Condensate to Boiler Plant

2.2.1.2.9 Flash Condensate to Produce Lower Pressure Steam
2.2.1.2.10 Use Steam Condensate for Hot Water Supply (Non Potable)

2.2.1.3 Leaks and Insulation
2.2.1.3.1 Insulate Steam Lines
2.2.1.3.2 Repair Faulty Insulation on Steam Lines
2.2.1.3.3 Repair Leaks in Lines and Valves
2.2.1.3.4 Eliminate Leaks in High Pressure Reducing Stations
2.2.1.3.5 Repair and Eliminate Steam Leaks

2.2.1.4 Distillation
2.2.1.4.1 Operate Distillation Columns Efficiently
2.2.1.4.2 Upgrade Distillation Hardware

2.2.1.5 Other
2.2.1.5.1 Clean Steam Coils in Processing Tanks
2.2.1.5.2 Maintain Steam Jets Used for Vacuum System
2.2.1.5.3 Optimize Operation of Multi-Stage Vacuum Steam Jets
2.2.1.5.4 Reduce Excess Steam Bleeding
2.2.1.5.5 Use Minimum Steam Operating Pressure
2.2.1.5.6 Substitute Hot Process Fluids for Steam
2.2.1.5.7 Close Off Unneeded Steam Lines
2.2.1.5.8 Use Heat Exchange Fluids Instead of Steam in Pipeline Tracing Systems
2.2.1.5.9 Turn Off Steam Tracing During Mild Weather
2.2.1.5.10 Substitute Air for Steam to Atomize Oil

2.2.2 Heating

2.2.2.1 Operation
2.2.2.1.1 Use Optimum Temperature
2.2.2.1.2 Use Minimum Safe Oven Ventilation

2.2.2.2 Hardware
2.2.2.2.1 Use Immersion Heating in Tanks, Melting Pots, Etc.
2.2.2.2.2 Convert Liquid Heaters from Underfiring to Immersion or Submersion Heating
2.2.2.2.3 Enhance Sensitivity of Temperature Control and Cutoff

2.2.3 Heat Treating

2.2.3.1 General
2.2.3.1.1 Heat Treat Parts Only to Required Specifications or Standards
2.2.3.1.2 Minimize Non-essential Material in Heat Treatment Process
2.2.3.1.3 Use Batch Firing with Kiln "Furniture" Designed Specifically for the Job

2.2.4 Heat Recovery

2.2.4.1 Flue Gas - Recuperation
2.2.4.1.1 Use Waste Heat from Hot Flue Gases to Preheat Combustion Air
2.2.4.1.2 Use Flue Gas Heat to Preheat Boiler Feedwater
2.2.4.1.3 Use Hot Flue Gases to Preheat Wastes for Incinerator Boiler

2.2.4.2 Flue Gas - Other Uses
2.2.4.2.1 Install Waste Heat Boiler to Provide Direct Power
2.2.4.2.2 Use Waste Heat from Hot Flue Gases to Generate Steam for Processes or Resale
2.2.4.2.3 Install Waste Heat Boiler to Produce Steam
2.2.4.2.4 Use Heat in Flue Gases to Preheat Products or Material Going into Ovens, Dryers, etc.

2.2.4.2.5 Use Flue Gases to Heat Process or Service Water
2.2.4.2.6 Use Waste Heat from Hot Flue Gases to Heat Space Conditioning Air
2.2.4.2.7 Use Waste Heat from Hot Flue Gases to Preheat Incoming Fluids
2.2.4.2.8 Use Hot Flue Gases in Radiant Heater for Space Heating, Ovens, Dryers, etc.

2.2.4.3 Other Process Waste Heat
2.2.4.3.1 Preheat Boiler Makeup Water with Waste Process Heat
2.2.4.3.2 Preheat Combustion Air with Waste Heat
2.2.4.3.3 Re-use or Recycle Hot or Cold Process Exhaust Air, or Exchange Heat with Incoming Air
2.2.4.3.4 Use Hot Process Fluids to Preheat Incoming Process Fluids
2.2.4.3.5 Recover Waste Heat from Equipment
2.2.4.3.6 Recover Heat from Oven Exhaust
2.2.4.3.7 Heat Water with Exhaust Heat
2.2.4.3.8 Recover Heat from Exhausted Steam
2.2.4.3.9 Recover Heat from Hot Waste Water
2.2.4.3.10 Recover Heat from Engine Exhausts
2.2.4.3.11 Recover Heat from Air Compressor
2.2.4.3.12 Recover Heat from Compressed Air Dryers
2.2.4.3.13 Recover Heat from Refrigeration Condensers
2.2.4.3.14 Recover Heat from Transformers

2.2.4.4 Miscellaneous
2.2.4.4.1 Use Cooling Air Which Cools Hot Work Pieces for Space Heating or Make-Up Air in Cold Weather
2.2.4.4.2 Use "Heat Wheel" or Other Heat Exchanger to Cross-Exchange Building Exhaust Air with Make-up Air
2.2.4.4.3 Use Recovered Heat from Lighting Fixtures for Useful Purpose, that is, to Operate Absorption Cooling Equipment
2.2.4.4.4 Recover Heat in Domestic Hot Water Going to Drain
2.2.4.4.5 Use Exhaust Heat from Building for Snow and Ice Removal from Walks, Driveways, Parkways, Parking Lots, etc.
2.2.4.4.6 Heat Service Hot Water with Air Conditioning Equipment
2.2.4.4.7 Recover Heating or Cooling Effect from Ventilation Exhaust Air to Precondition Incoming Ventilation Air

2.2.5 Heat Containment

2.2.5.1 Insulation
2.2.5.1.1 Insulate Bare Equipment
2.2.5.1.2 Increase Insulation Thickness
2.2.5.1.3 Cover Open Tanks with Floating Insulation to Minimize Energy Losses
2.2.5.1.4 Cover Open Tanks
2.2.5.1.5 Use Optimum Thickness Insulation
2.2.5.1.6 Use Economic Thickness of Insulation for Low Temperatures

2.2.5.2 Isolate Hot Systems from Cold Systems
2.2.5.2.1 Isolate Steam Lines to Avoid Heating Air Conditioned Areas
2.2.5.2.2 Isolate Hot or Cold Equipment
2.2.5.2.3 Reduce Infiltration to Refrigerated Areas; Isolate Hot Equipment from Refrigerated Areas
2.2.5.2.4 Avoid Cooling of Process Streams or Materials That Must Subsequently be Heated
2.2.5.2.5 Eliminate Cooling of Process Streams Which Subsequently Must Be Heated and Vice Versa

2.2.5.3 Minimize Infiltration
- 2.2.5.3.1 Resize Charging Openings or Add Movable Cover or Door
- 2.2.5.3.2 To Drive Off Combustible Solvents, Use Only Amount of Air Necessary to Prevent Explosion Hazard and to Protect Personnel
- 2.2.5.3.3 Replace Air Curtain Doors with Solid Doors

2.2.6 Cooling

2.2.6.1 Cooling Towers
- 2.2.6.1.1 Operate Cooling Tower at Constant Outlet Temperature to Avoid Subcooling
- 2.2.6.1.2 Use Cooling Tower Water Instead of Refrigeration when Outside Temperatures Allow
- 2.2.6.1.3 Use Antifreeze in Cooling Towers to Allow Winter Use
- 2.2.6.1.4 Use Either Cooling Tower or Economizer Cooling to Replace Chiller Cooling

2.2.6.2 Chillers and Refrigeration
- 2.2.6.2.1 Modify Refrigeration System to Enable Compressor to Operate at a Lower Pressure
- 2.2.6.2.2 Utilize a Less Expensive Cooling Method
- 2.2.6.2.3 Minimize Condenser Cooling Water Temperature
- 2.2.6.2.4 Use Cold Waste Water to Cool Chiller Feed Water
- 2.2.6.2.5 Chill Water to the Highest Temperature Possible
- 2.2.6.2.6 Avoid Frost Formation on Evaporators
- 2.2.6.2.7 Use Multiple-effect Evaporators

2.2.6.3 Other
- 2.2.6.3.1 Shut Off Cooling if Cold Outside Air Will Cool Process
- 2.2.6.3.2 Use Outside Cold Water Source as a Continuous Supply of Cooling Water
- 2.2.6.3.3 Use Waste Heat Low Pressure Steam for Absorption Refrigeration
- 2.2.6.3.4 Use Outside Air for Freezing
- 2.2.6.3.5 Use Highest Temperature for Chilling or Cold Storage
- 2.2.6.3.6 Utilize Pond or Lake as a Heat Sink
- 2.2.6.3.7 Use Cascade System of Recirculating During Cold Weather to Avoid Sub-Cooling

2.2.7 Drying

2.2.7.1 Use of Air
- 2.2.7.1.1 Utilize Outside Air Instead of Conditioned Air for Drying

2.3 Electrical Power

2.3.1 Demand Management

2.3.1.1 Thermal Energy Storage
- 2.3.1.1.1 Heat Water During Off-Peak Periods and Store for Later Use
- 2.3.1.1.2 Store Heated/Cooled Water for Use During Peak Demand Periods
- 2.3.1.1.3 Make Ice During Off Peak Hours for Cooling

2.3.1.2 Other
- 2.3.1.2.1 Use Power During Off-Peak Periods
- 2.3.1.2.2 Use Fossil Fuel Powered Generator During Peak Demand Periods
- 2.3.1.2.3 Locate Causes of Electrical Power Demand Charges, and Reschedule Plant Operations to Avoid Peaks
- 2.3.1.2.4 Recharge Batteries on Materials Handling Equipment During Off-Peak Demand Periods
- 2.3.1.2.5 Consider Three or Four Days Around-the-Clock Operation Rather Than One or Two Shifts Per Day
- 2.3.1.2.6 Shift from Daytime to Nighttime Operation
- 2.3.1.2.7 Schedule Routine Maintenance During Non-Operating Periods

2.3.1.2.8 Overlap the Work Hours of Custodial Services with Normal Day Hours
2.3.1.2.9 Use Demand Controller or Load Shedder

2.3.2 Power Factor

2.3.2.1 General
2.3.2.1.1 Use Power Factor Controllers
2.3.2.1.2 Optimize Plant Power Factor

2.3.3 Generation of DC Power

2.3.3.1 General
2.3.3.1.1 Replace DC Equipment with AC Equipment
2.3.3.1.2 Install Efficient Rectifiers

2.3.4 Cogeneration

2.3.4.1 General
2.3.4.1.1 Use Steam Pressure Reduction to Generate Power
2.3.4.1.2 Use Waste Heat to Produce Steam to Drive a Steam Turbine-Generator
2.3.4.1.3 Burn Fossil Fuel to Produce Steam to Drive a Steam Turbine-Generator and Use Steam Exhaust for Heat
2.3.4.1.4 Burn Waste to Produce Steam to Drive a Steam Turbine Generator Set and Use Steam Exhaust for Heat
2.3.4.1.5 Use a Fossil Fuel Engine-Generator Set to Cogenerate Electricity and Heat
2.3.4.1.6 Use Combined Cycle Gas Turbine Generator Sets with Waste Heat Boilers Connected to Turbine Exhaust
2.3.4.1.7 Use Waste Heat with a Closed-Cycle Gas Turbine-Generator Set to Cogenerate Electricity and Heat
2.3.4.1.8 Use Existing Dam to Generate Electricity
2.3.4.1.9 Replace Electric Motors with Back Pressure Steam Turbines and Use Exhaust Steam for Process Heat

2.3.5 Other

2.3.5.1 Transformers
2.3.5.1.1 Use Plant Owned Transformers or Lease Transformers from Utility
2.3.5.1.2 De-Energize Excess Transformer Capacity
2.3.5.1.3 Consider Power Loss as Well as Initial Loads and Load Growth in Down-Sizing Transformers

2.3.5.2 Conductor Size
2.3.5.2.1 Reduce Load on Electrical Conductor to Reduce Heating Losses
2.3.5.2.2 Increase Electrical Conductor Size to Reduce Distribution Losses

2.4 Motor Systems

2.4.1 Motors

2.4.1.1 Operation
2.4.1.1.1 Utilize Energy-Efficient Belts and Other Improved Mechanisms

2.4.1.2 Hardware Upgrade
2.4.1.2.1 Replace Over-Size Motors and Pumps with Optimum Size
2.4.1.2.2 Size Electric Motors for Peak Operating Efficiency
2.4.1.2.3 Use Multiple Speed Motors or ASD for Variable Pump, Blower and Compressor Loads
2.4.1.2.4 Use Most Efficient Type of Electric Motors

2.4.2 Air Compressors

2.4.2.1 Operations
- 2.4.2.1.1 Reduce the Pressure of Compressed Air to the Minimum Required
- 2.4.2.1.2 Eliminate or Reduce Compressed Air Used for Cooling Product, Equipment, or for Agitating Liquids
- 2.4.2.1.3 Eliminate Permanently the Use of Compressed Air
- 2.4.2.1.4 Cool Compressor Air Intake with Heat Exchanger
- 2.4.2.1.5 Remove or Close off Unneeded Compressed Air Lines
- 2.4.2.1.6 Eliminate Leaks in Inert Gas and Compressed Air Lines and Valves
- 2.4.2.1.7 Use Compressor Air Filters
- 2.4.2.1.8 Substitute for Compressed Air Cooling with Either Water or Air Cooling
- 2.4.2.1.9 Do Not Use Compressed Air for Personal Cooling

2.4.2.2 Hardware Upgrade
- 2.4.2.2.1 Install Compressor Air Intakes in Coolest Locations
- 2.4.2.2.2 Install Adequate Dryers on Air Lines to Eliminate Blowdown
- 2.4.2.2.3 Install Direct Acting Units in Place of Compressed Air Pressure System in Safety System
- 2.4.2.2.4 Upgrade Controls on Screw Compressors

2.4.3 Other

2.4.3.1 Operations
- 2.4.3.1.1 Recover Mechanical Energy
- 2.4.3.1.2 Improve Lubrication Practices
- 2.4.3.1.3 Provide Proper Maintenance and Lubrication of Motor Driven Equipment

2.4.3.2 Hardware
- 2.4.3.2.1 Upgrade Obsolete Equipment
- 2.4.3.2.2 Use or Replace with Energy Efficient Substitutes
- 2.4.3.2.3 Use Optimum Size and Capacity Equipment
- 2.4.3.2.4 Replace Hydraulic or Pneumatic Equipment with Electric Equipment
- 2.4.3.2.5 Upgrade Conveyors

2.5 Industrial System Design

2.5.1 Miscellaneous Strategies

2.5.1.1 Thermal
- 2.5.1.1.1 Convert from Indirect to Direct Fired Systems
- 2.5.1.1.2 Use Continuous Equipment Which Retains Process Heating Conveyors Within the Heated Chamber
- 2.5.1.1.3 Use Direct Flame Impingement or Infrared Processing for Chamber Type Heating
- 2.5.1.1.4 Use Shaft Type Furnaces for Preheating Incoming Material

2.5.1.2 Mechanical
- 2.5.1.2.1 Redesign Flow to Minimize Mass Transfer Length
- 2.5.1.2.2 Replace High Resistance Ducts, Pipes, and Fittings
- 2.5.1.2.3 Reduce Fluid Flow Rates
- 2.5.1.2.4 Use Gravity Feeds Wherever Possible
- 2.5.1.2.5 Size Air Handling Grills, Duct, and Coils to Minimize Air Resistance

2.5.1.3 Other
- 2.5.1.3.1 Modify Dye Beck
- 2.5.1.3.2 Modify Textile Dryers
- 2.5.1.3.3 Convert from Batch to Continuous Operation

2.5.1.3.4 Redesign Process
2.5.1.3.5 Change Product Design to Reduce Processing Energy Requirements
2.5.1.3.6 Use Small Number of High Output Units Instead of Many Small Inefficient Units
2.5.1.3.7 Avoid Electrically-Powered Animated Displays

2.6 Miscellaneous Operational Changes

2.6.1 Maintenance

2.6.1.1 Miscellaneous
2.6.1.1.1 Reduce Hot Water Temperature to the Minimum Required
2.6.1.1.2 Use Cold Water for Cleanup Whenever Possible
2.6.1.1.3 Maintain Air Filters by Cleaning or Replacement
2.6.1.1.4 Adjust Vents to Minimize Energy Use
2.6.1.1.5 Remove Unneeded Service Lines to Eliminate Potential Leaks
2.6.1.1.6 Periodically Calibrate the Sensors Controlling Louvers and Dampers on Buildings
2.6.1.1.7 Establish Equipment Maintenance Schedule
2.6.1.1.8 Keep Equipment Clean
2.6.1.1.9 Keep Solid Fuels Dry

2.6.2 Cut Back or Turn Off Equipment

2.6.2.1 Turn Off Equipment Not In Use
2.6.2.1.1 Turn Off Equipment When Not in Use
2.6.2.1.2 Turn Off Equipment During Lunch Breaks, Reduce Operating Time of Equipment
2.6.2.1.3 Turn Off Steam or Hot Water Lines Leading to Space Heating Units During Mild Weather
2.6.2.1.4 Shut Off Pilots in Standby Equipment
2.6.2.1.5 Shut Off Air Conditioning in Winter Heating Season
2.6.2.1.6 Shut Off Cooling Water When Not Required
2.6.2.1.7 Shut Off All Laboratory Fume Hoods When Not in Use
2.6.2.1.8 Conserve Energy by Efficient Use of Water Cooler and Vending Machines

2.6.2.2 Schedule Equipment For Optimal Performance
2.6.2.2.1 Use Most Efficient Equipment at Its Maximum Capacity and Less Efficient Equipment Only When Necessary
2.6.2.2.2 Use Drying Oven (Batch Type) on Alternate Days or Other Optimum Schedule to Run Equipment with Full Loads
2.6.2.2.3 Schedule Use of Elevators to Conserve Energy
2.6.2.2.4 Schedule Baking Times of Small and Large Components to Minimize Use of Energy

2.6.2.3 Automatic Equipment Operation
2.6.2.3.1 Utilize Controls to Operate Equipment Only When Needed
2.6.2.3.2 Install Set-back Timers

2.6.2.4 Run Equipment In Off-Loaded Mode
2.6.2.4.1 Reduce Temperature of Process Heating Equipment When on Standby
2.6.2.4.2 Minimize Operation of Equipment Required to be Maintained in Standby Condition

2.7 Building and Grounds

2.7.1 Lighting

2.7.1.1 Level
2.7.1.1.1 Reduce Illumination to Minimum Necessary for Effective Operation and Safety
2.7.1.1.2 Reduce Exterior Building and Grounds Illumination to Minimum Safe Level

2.7.1.2 Operation
- 2.7.1.2.1 Utilize Daylight Whenever Possible in Lieu of Artificial Light
- 2.7.1.2.2 Disconnect Ballasts
- 2.7.1.2.3 Keep Lamps and Reflectors Clean

2.7.1.3 Hardware
- 2.7.1.3.1 Lower Light Fixtures in High Ceiling Areas
- 2.7.1.3.2 Install Timers on Light Switches in Little Used Areas
- 2.7.1.3.3 Use Separate Switches on Perimeter Lighting Which May be Turned Off When Natural Light is Available
- 2.7.1.3.4 Use Photocell Controls
- 2.7.1.3.5 Utilize Higher Efficiency, Lower Wattage Lamps or Ballasts
- 2.7.1.3.6 Use More Efficient Light Source
- 2.7.1.3.7 Add Area Lighting Switches to Allow Smaller Areas to be Darkened When Not in Use

2.7.2 Space Heating and Cooling

2.7.2.1 Maintenance
- 2.7.2.1.1 Clean Air Conditioning Refrigerant Condensers to Reduce Compressor Horsepower-Check Cooling Water Treatment
- 2.7.2.1.2 Install or Upgrade Insulation on HVAC Distribution Systems

2.7.2.2 Operation
- 2.7.2.2.1 Maintain Space Temperature Lower During the Winter Season and Higher During the Summer Season
- 2.7.2.2.2 Air Condition Only Space in Use
- 2.7.2.2.3 Cool Smallest Space Necessary
- 2.7.2.2.4 Reduce or Eliminate Space Heating/Cooling During Non-Working Hours
- 2.7.2.2.5 Close Outdoor Air Dampers During Warm-up or Cool-down Periods Each Day
- 2.7.2.2.6 Use Computer Programs to Optimize HVAC Performance
- 2.7.2.2.7 Use Water Sparingly on Air Conditioning Exchanger to Improve Heat Transfer and Increase Air Conditioner Efficiency
- 2.7.2.2.8 Direct Hot Exhaust Air Outdoors in Summer; Avoid Introducing High-Moisture Exhaust Air into Air Conditioning System
- 2.7.2.2.9 Avoid Introducing Hot, Humid, or Dirty Air Into HVAC System

2.7.2.3 Hardware
- 2.7.2.3.1 Use Radiant Heater for Spot Heating Rather Targeting Entire Area
- 2.7.2.3.2 Install Timers and/or Thermostats
- 2.7.2.3.3 Separate Controls of Air Handlers from AC/Heating Systems
- 2.7.2.3.4 Use Heat Pump for Space Conditioning
- 2.7.2.3.5 Change Zone Reheat Coils to Low Pressure Variable Air Volume Boxes
- 2.7.2.3.6 Lower Ceiling to Reduce Conditioned Space
- 2.7.2.3.7 Use Properly Designed and Sized HVAC Equipment
- 2.7.2.3.8 Improve Interior Air Circulation with Destratification Fans or other Methods
- 2.7.2.3.9 Revise Smoke Cleanup from Operations
- 2.7.2.3.10 Use Direct Air Supply to Exhaust Hoods
- 2.7.2.3.11 Lower Compressor Pressure Through A/C System Modification
- 2.7.2.3.12 Interlock Heating and Air Conditioning Systems to Prevent Simultaneous Operation

2.7.2.4 Utilize Evaporation
- 2.7.2.4.1 Reduce Air Conditioning Load by Evaporating Water from Roof
- 2.7.2.4.2 Utilize an Evaporative Air Pre-cooler or Other Heat Exchanger in AC System

2.7.2.5 General

2.7.2.5.1 Reschedule and Rearrange Multiple-Source Heating Systems to Minimize Redundant Heating and to Burn Least Expensive Fuels

2.7.3 Ventilation

2.7.3.1 General

2.7.3.1.1 Revise Conference Room Ventilation System to Shut Off When Room is Not in Use
2.7.3.1.2 Minimize Use of Outside Make-Up Air for Ventilation Except When Used for Economizer Cycle
2.7.3.1.3 Recycle Air for Heating, Ventilation and Air Conditioning to Maximum Extent
2.7.3.1.4 Reduce Ventilation Air
2.7.3.1.5 Reduce Building Exhausts and Thus Make-up Air; Reduce Ventilation Air to Minimum Safe Levels
2.7.3.1.6 Centralize control of exhaust fans to Ensure Their Shutdown, or Establish Program to Ensure Manual Shutdown

2.7.4 Building Envelope

2.7.4.1 Infiltration

2.7.4.1.1 Replace Broken Windows and/or Window Sash
2.7.4.1.2 Keep Doors and Windows Shut to Retain Heated or Air Conditioned Air
2.7.4.1.3 Keep Loading Dock Doors Closed When Not In Use
2.7.4.1.4 Install Air Seals Around Truck Loading Dock Doors
2.7.4.1.5 Close Holes and Openings in Building Such as Broken Windows
2.7.4.1.6 Install Weather Stripping on Windows and Doors
2.7.4.1.7 Eliminate Unused Roof Openings, Seal Unneeded Dampers, Louvers, and Flues
2.7.4.1.8 Utilize Sensors Controlling Roof and Wall Openings

2.7.4.2 Solar Loading

2.7.4.2.1 Reduce Glazed Areas in Buildings
2.7.4.2.2 Plant Trees or Shrubs Near Windows to Shield From Sunlight
2.7.4.2.3 Reduce Heat Gain by Window Tinting
2.7.4.2.4 Shade Windows From Summer Sun

2.7.4.3 Other

2.7.4.3.1 Insulate Walls, Ceilings, and Roofs
2.7.4.3.2 Use Proper Thickness of Insulation on Building Envelope
2.7.4.3.3 Use Double or Triple Glazed Windows to Maintain Higher Relative Humidity and to Reduce Heat Losses
2.7.4.3.4 Install Storm Windows and Doors

2.8 Administrative

2.8.1 General

2.8.1.1 Utility Costs

2.8.1.1.1 Check for Accuracy of Utility Meters
2.8.1.1.2 Combine Gas Meters
2.8.1.1.3 Purchase Gas Directly from a Contract Gas Supplier
2.8.1.1.4 Change Rate Schedules or Make Other Changes in Electric Service
2.8.1.1.5 Base Fuel Oil Charges on Usage Rather than Area Occupied
2.8.1.1.6 Check for Accuracy of Power Meter

2.8.1.2 Fiscal

2.8.1.2.1 Apply for Tax-Free Status for Energy Purchases
2.8.1.2.2 Use Utility Controlled Power Management
2.8.1.2.3 Pay Utility Bills on Time

2.9 Alternative Energy Usage

2.9.1 General

2.9.1.1 Solar

2.9.1.1.1 Use Solar Heat to Heat Make-up Air
2.9.1.1.2 Use Solar Heat to Heat Water
2.9.1.1.3 Use Solar Heat for Heat

2.10 Shipping, Distribution and Transportation

2.10.1 General

2.10.1.1 Shipping

2.10.1.1.1 Consolidate Freight Shipments and/or Deliveries
2.10.1.1.2 Reduce Delivery Schedules

2.10.1.2 Vehicles

2.10.1.2.1 Consider Intermediate or Economy Size Autos and Trucks for Company Sales and Plant Fleets
2.10.1.2.2 Size Trucks to Job
2.10.1.2.3 Add Air Shields to Long Distance Trucks to Increase Fuel Mileage
2.10.1.2.4 Shut Down Truck Engines While Loading, Unloading, or Waiting
2.10.1.2.5 Schedule Regular Maintenance to Maintain Efficiency of Truck Engines
2.10.1.2.6 Increase Efficiency of Trucks
2.10.1.2.7. Adjust and Maintain Fork Lift Trucks for Most Efficient Operation

3 Waste Minimization/Pollution Prevention

3.1 Operational Upgrades

3.1.1 Change Procedures and/or Equipment

3.1.1.1 Process Specific

3.1.1.1.1 Cover Ink Containers When Not in Use
3.1.1.1.2 Use Dedicated Presses for Each Color
3.1.1.1.3 Use Glass Marbles to Raise Fluid Levels of Chemicals to the Brim to Reduce Contact with Atmospheric Oxygen
3.1.1.1.4 Reuse High Ferrous Metal Dust as Raw Material
3.1.1.1.5 Order Paint Pigments in Paste Form Instead of Dry Powder to Eliminate Hazardous Dust Waste
3.1.1.1.6 Repair or Upgrade Grate Conveyors to Minimize Loss of Coal Fines

3.1.1.2 Apply Material Streams Completely

3.1.1.2.1 Use More Efficient Adhesive Applicators

3.1.1.3 Stripping

3.1.1.3.1 Use Mechanical Stripping Methods
3.1.1.3.2 Use Cryogenic Stripping

3.1.1.4 Scheduling Change

3.1.1.4.1 Schedule Jobs to Minimize the Need for Cleanup (Light Colors Before Dark)
3.1.1.4.2 Schedule Production Runs to Minimize Color Changes

3.1.1.5 Desulfurization/Slag Management
- 3.1.1.5.1 Treat Desulfurization Slag in a Deep Quench Tank Instead of Spraying Water onto an Open Pile to Reduce Air Emissions
- 3.1.1.5.2 Use High Quality Scrap (Low Sulfur) to Reduce Hazardous Sludge Generation
- 3.1.1.5.3 Alter Product Requirements to Eliminate Unnecessary Use of Desulfurizing Agent (Calcium Carbide)
- 3.1.1.5.4 Use an Alternative Desulfurizing Agent to Eliminate Hazardous Slag Formation

3.1.1.6 Eliminate/Reduce an Operation
- 3.1.1.6.1 Eliminate/Reduce an Operation

3.1.1.7 Change Product Specs
- 3.1.1.7.1 Change Product Specs
- 3.1.1.7.2 Revise Raw Material Specs
- 3.1.1.7.3 Use a Different Raw Material
- 3.1.1.7.4 Use a Recycled Raw Material

3.1.1.8 Change Product Packaging
- 3.1.1.8.1 Use Less Wasteful Packaging

3.1.1.9 Byproduct Use
- 3.1.1.9.1 Eliminate a Byproduct
- 3.1.1.9.2 Make a New Byproduct

3.1.1.10 Other
- 3.1.1.10.1 Change Procedures/Equipment
- 3.1.1.10.2 Add a New Operation
- 3.1.1.10.3 Change Operating Conditions
- 3.1.1.10.4 Reduce Scrap Production
- 3.1.1.10.5 Convert from Batch Operation to Continuous Processing
- 3.1.1.10.6 Use Automatic Flow Control
- 3.1.1.10.7 Use Silhouette Entry Cover to Reduce Evaporation Area
- 3.1.1.10.8 Closely Monitor Solutions and Make Small Additions to Maintain Solution Strength Instead of Large Infrequent Additions

3.1.2 Avoid Mixing Waste Streams

3.1.2.1 Dragout Reduction
- 3.1.2.1.1 Slow Insertion and Withdrawal of Parts from Vapor Degreasing Tank to Prevent Vapor Drag-out
- 3.1.2.1.2 Allow Drainage Before Withdrawing Object
- 3.1.2.1.3 Preinspect Parts to Prevent Drag-in of Solvents and Other Cleaners
- 3.1.2.1.4 Reduce Solution Drag-Out to Prevent Solution Loss
- 3.1.2.1.5 Extend Solution Life by Minimizing Drag-In
- 3.1.2.1.6 Prevent Solution Drag-Out from Upstream Tanks
- 3.1.2.1.7 Reduce Drag-In with Better Rinsing to Increase Solution Life
- 3.1.2.1.8 Lower the Concentration of Plating Baths
- 3.1.2.1.9 Use Drag-Out Reduction Methods (Gravure)-See Surface Coating

3.1.2.2 Rinsing Strategies

- 3.1.2.2.1 Use Reactive Rinsing
- 3.1.2.2.2 Reduce Water Use with Counter Current Rinsing
- 3.1.2.2.3 Use Fog Nozzles over Plating Tanks and Spray Rinsing Instead of Immersion Rinsing
- 3.1.2.2.4 Mechanically and Air Agitate Rinse Tanks for Complete Mixing
- 3.1.2.2.5 Use a Still Rinse as the Initial Rinsing Stage

3.1.2.2.6 Use Counter Current Washing in Photo Processors
3.1.2.2.7 Use Counter-Current Rinsing to Reduce Rinse Water Volume (Gravure)

3.1.2.3 Other
3.1.2.3.1 Avoid Contamination of Scrap Glass and Reuse as Feed Stock
3.1.2.3.2 Develop Segregated Sewer Systems for Low Suspended Solids, High Suspended Solids, Strong Wastes, and Sanitary Sewer
3.1.2.3.3 Use Separate Treatments for Each Type of Solution and Sell Sludge to a Recycler
3.1.2.3.4 Segregate Spent Solvents (by Color) and Reuse in Subsequent Washings
3.1.2.3.5 Use Squeegees to Prevent Chemical Carry-over in Manual Processing Operations

3.1.3 CAD/CAM

3.1.3.1 General
3.1.3.1.1 Optimize Dye Design

3.2 Equipment Upgrades

3.2.1 General

3.2.1.1 Fault Tolerance
3.2.1.1.1 Install Redundant Key Pumps and Other Equipment to Avoid Losses Caused by Equipment Failure and Routine Maintenance

3.2.1.2 Painting Operations
3.2.1.2.1 Convert to Electrostatic Powder Coating
3.2.1.2.2 Convert from Water Curtain Spray Booths to a Dry System

3.2.1.3 Process Specific Upgrades
3.2.1.3.1 Install Mixers on Each Cleaning Tank
3.2.1.3.2 Increase Freeboard Space and Install Chillers on Vapor Degreasers
3.2.1.3.3 Eliminate Chemical Etching and Plating by Using Alternative Printing Technologies (Presensitized Lithographic, Plastic or Photopolymer, Hot Metal, or Flexographic)
3.2.1.3.4 Use High Purity Anodes to Increase Solution Life
3.2.1.3.5 Extend Solution Life with Filtering or Carbonate Freezing
3.2.1.3.6 Use "Wash-Less" Processing Equipment
3.2.1.3.7 Use Induction Furnaces Instead of Electric Arc or Cupola Furnaces to Reduce Dust and Fumes

3.2.1.4 Tank Design
3.2.1.4.1 Use Cylindrical Tanks with Height to Diameter Ratios Close to One to Reduce Wetted Surface
3.2.1.4.2 Use Tanks with a Conical Bottom Outlet Section to Reduce Waste Associated with the Interface of Two Liquids

3.2.1.5 Automate Tasks
3.2.1.5.1 Install Web Break Detectors to Prevent Excessive Waste Paper
3.2.1.5.2 Use Automatic Cleaning Equipment
3.2.1.5.3 Convert to Robotic Painting
3.2.1.5.4 Automate Ink Key Setting System
3.2.1.5.5 Use Ink Water Ratio Sensor
3.2.1.5.6 Use Automatic Ink Levelers
3.2.1.5.7 Use Automated Plate Benders
3.2.1.5.8 Automate Ink Mixing
3.2.1.5.9 Use Electronic Imaging and Laser Plate Making
3.2.1.5.10 Use an Automatic Plate Processor
3.2.1.5.11 Increase Use of Automation

3.2.1.6 System Monitoring

3.2.1.6.1 Closely Monitor Chemical Additions to Increase Bath Life

3.3 Post Generation Treatment/Minimization

3.3.1 General

3.3.1.1 Neutralization

3.3.1.1.1 Adjust pH for Neutralization
3.3.1.1.2 Utilize Oxidation/Reduction for Neutralization
3.3.1.1.3 Use Other Methods for Neutralization

3.3.1.2 Removal of Contaminants

3.3.1.2.1 Use Screening, Magnetic Separation to Remove Contaminants
3.3.1.2.2 Use Filtration, Centrifuging to Remove Contaminants
3.3.1.2.3 Use Decanting, Flotation to Remove Contaminants
3.3.1.2.4 Use Cyclonic Separation to Remove Contaminants
3.3.1.2.5 Use Distillation, Evaporation to Remove Contaminants
3.3.1.2.6 Use Absorption, Extraction to Remove Contaminants
3.3.1.2.7 Use Adsorption, Ion Exchange to Remove Contaminants
3.3.1.2.8 Utilize Other Methods to Remove Contaminants

3.3.1.3 Material Concentration

3.3.1.3.1 Use Evaporation to Concentrate Material
3.3.1.3.2 Use Reverse Osmosis to Concentrate Material
3.3.1.3.3 Use Other Waste Concentration Methods

3.4 Water Use

3.4.1. General

3.4.1.1 Close Cycle Water Use

3.4.1.1.1 Employ a Closed Cycle Mill Process to Minimize Waste Water Production
3.4.1.1.2 Recovery Metals from Rinse Water (Evap., Ion Exchange, R.O., Electrolysis, Electrodialysis) and Reuse Rinse Water
3.4.1.1.3 Treat and Reuse Rinse Waters
3.4.1.1.4 Replace City Water with Recycled Water via Cooling Tower
3.4.1.1.5 Recover and Reuse Cooling Water
3.4.1.1.6 Meter Recycled Water (To Reduce Sewer Charges)

3.4.1.2 Limit Use

3.4.1.2.1 Minimize Water Usage
3.4.1.2.2 Carefully Control Water Level in Mass Finishing Equipment
3.4.1.2.3 Use Counter Current Rinsing to Reduce Waste Water
3.4.1.2.4 Eliminate Leaks in Water Lines and Valves
3.4.1.2.5 Meter Waste Water
3.4.1.2.6 Use Flow Control Valves on Equipment to Optimize Water Use
3.4.1.2.7 Minimize Water Use in Lavatories by Choosing Appropriate Fixtures and Valves
3.4.1.2.8 Replace Water Cooling on Processes with Air Cooling Where Possible
3.4.1.2.9 Use Minimum Cooling Water to Bearings

3.4.1.3 Water Quality

3.4.1.3.1 Minimize Contamination of Water Before Treatment
3.4.1.3.2 Use Deionized Water in Upstream Rinse Tanks
3.4.1.3.3 Clean Fouling from Water Lines Regularly

3.4.1.4 Chlorination
- 3.4.1.4.1 Replace the Chlorination Stage with an Oxygen or Ozone Stage
- 3.4.1.4.2 Recycle Chlorination Stage Process Water
- 3.4.1.4.3 Use Water from the Countercurrent Washing System in the Chlorination Stage
- 3.4.1.4.4 Perform High Consistency Gas Chase Chlorination

3.5 Recycling

3.5.1 Liquid Waste

3.5.1.1 Oil
- 3.5.1.1.1 Filter and Reuse Hydraulic Oil

3.5.1.2 Ink
- 3.5.1.2.1 Recycle Waste Ink and Cleanup Solvent

3.5.1.3 White Water
- 3.5.1.3.1 Recycle White Water
- 3.5.1.3.2 Reuse Rich White Water in Other Applications

3.5.1.4 Other
- 3.5.1.4.1 Recover Dye from Waste Waters
- 3.5.1.4.2 Treat and Reuse Equipment Cleaning Solutions
- 3.5.1.4.3 Return Spent Solutions to the Manufacturer
- 3.5.1.4.4 Recycle Spent Tanning Solution
- 3.5.1.4.5 Recover and Reuse Spent Acid Baths
- 3.5.1.4.6 Utilize a Central Coolant System for Cleaning and Reuse of Metal Working Fluid
- 3.5.1.4.7 Reprocess Spent Oils on Site for Reuse

3.5.2 Solid Waste

3.5.2.1 General
- 3.5.2.1.1 Reuse Scrap Glass as Feed Stock
- 3.5.2.1.2 Regrind and Reuse Scrap Plastic Parts
- 3.5.2.1.3 Reuse Scrap Printed Paper for Make-ready
- 3.5.2.1.4 Avoid Contamination of Flashing and Reject Castings and Reuse as Feed Stock
- 3.5.2.1.5 Avoid Contamination of End Pieces and Reuse as Feed Stock
- 3.5.2.1.6 Recycle Nonferrous Dust

3.5.2.2 Sand
- 3.5.2.2.1 Recycle Casting Sand
- 3.5.2.2.2 Use Sand for Other Purposes (for example, Construction Fill, Cover for Municipal Landfills)

3.5.2.3 Metals
- 3.5.2.3.1 Sell Used Plates to an Aluminum Recycler
- 3.5.2.3.2 Avoid Contamination of End Pieces and Reuse as Feed Stock
- 3.5.2.3.3 Recover Metals from Spent Solutions and Recycle
- 3.5.2.3.4 Recycle Processing Baths for Nickel Recovery
- 3.5.2.3.5 Recycle Film for Silver Recovery
- 3.5.2.3.6 Recover Metals from Casting Sand
- 3.5.2.3.7 Recycle Scrap Metal to Foundry
- 3.5.2.3.8 Segregate Metals for Sale to a Recycler
- 3.5.2.3.9 Separate (Flotation, Magnetic) and Recycle Scrap to Foundry
- 3.5.2.3.10 Separate Iron from Slag and Remelt

3.5.3 Other

3.5.3.1 Use In-process Recycling Whenever Possible
3.5.3.1.1 Recover and Reuse Waste Material
3.5.3.1.2 Salvage and Re-Use Process Waste
3.5.3.1.3 Increase Amount Of Waste Recovered For Resale

3.6 Waste Disposal

3.6.1 General

3.6.1.1 Sludge Maintenance
3.6.1.1.1 Use Alternative Flocculants to Minimize Sludge Volume
3.6.1.1.2 Use Filter or a Filter Press and Drying Oven to Reduce Sludge Volume
3.6.1.1.3 Remove Sludge from Tanks on a Regular Basis
3.6.1.1.4 Remove Sludge from Tanks on a Regular Basis
3.6.1.1.5 Use Precipitating Agents in Waste Water Treatment that Produce the Least Quantity of Waste

3.6.1.2 Other
3.6.1.2.1 Return Spent Solutions to the Manufacturer
3.6.1.2.2 Use a Less Expensive Method of Waste Removal
3.6.1.2.3 Install Equipment (for example, Compactor) to Reduce Disposal Costs

3.7 Maintenance

3.7.1 Cleaning/Degreasing

3.7.1.1 Mechanical Cleaning
3.7.1.1.1 Use an Industrial Vacuum for Spill Cleanup Instead of Absorbent
3.7.1.1.2 Use Squeegees Mops and Vacuums for Floor Cleaning
3.7.1.1.3 Use Mechanical Wipers for Cleaning of Vessels
3.7.1.1.4 Use Squeegees to Recover Clinging Product Prior to Rinsing

3.7.1.2 Minimize Amount of Cleaning
3.7.1.2.1 Eliminate the Need for Cleaning with Improved Handling Practices
3.7.1.2.2 Maximize Production Runs to Reduce Cleanings
3.7.1.2.3 Use Continuous Processing to Eliminate the Need for Inter-Run Cleaning
3.7.1.2.4 Install Dedicated Mixing Equipment to Optimize Reuse of Used Rinseate and to Preclude the Need for Inter-Run Cleaning
3.7.1.2.5 Shorten Paint Lines as Much as Possible to Reduce Line Cleaning Waste
3.7.1.2.6 Use Peel Coatings on Raw Materials to Eliminate Need for Cleaning

3.7.1.3 Minimize Rag Use
3.7.1.3.1 Use a Rag Recycle Service
3.7.1.3.2 Reuse Rags Until Completely Soiled
3.7.1.3.3 Use Rags Sized for Each Job
3.7.1.3.4 Wash and Reuse Rags On-Site
3.7.1.3.5 Minimize Use of Rags Through Worker Training
3.7.1.3.6 Use Press Cleanup Rags as Long as Possible Before Discarding

3.7.1.4 Miscellaneous
3.7.1.4.1 Minimize Part Contamination Before Washing
3.7.1.4.2 Use Liquid Spray (Water Based) Adhesive Instead of Bar Abrasives to Prevent Over Use of Material and Easier Part Cleaning
3.7.1.4.3 Improve Cleaning Efficiency by Maintaining Cleaning System (Rollers Cleanup Blade)
3.7.1.4.4 Use Dry Cleaning Methods Whenever Possible

3.7.1.4.5 Use High Pressure Wash Systems
3.7.1.4.6 Use Disposable Liners in Tanks
3.7.1.4.7 Use Teflon Lined Tanks
3.7.1.4.8 Clean Lines with Pigs Instead of Solvents or Aqueous Solutions
3.7.1.4.9 Use Clean In Place (CIP) Systems
3.7.1.4.10 Clean Equipment Immediately After Use

3.7.2 Spillage

3.7.2.1 Operations
3.7.2.1.1 Modify Material Application Methods to Prevent Material Spillage
3.7.2.1.2 Improved Material Handling (Mixing and Transfer) to Avoid Spills
3.7.2.1.3 Use More Efficient Spray Method for Gelcoat Application
3.7.2.1.4 Reduce or Eliminate Waste
3.7.2.1.5 Avoid Inserting Oversized Object to Reduce Piston Effect

3.7.2.2 Hardware
3.7.2.2.1 Improve Process Control to Prevent Spills of Material
3.7.2.2.2 Minimize Overflows or Spills by Installing Level Controls in Process Tanks and Storage Tanks
3.7.2.2.3 Install Shrouding on Machines to Prevent Splashing of Metal Working Fluids
3.7.2.2.4 Use Pumps and Piping to Decrease the Frequency of Spillage During Material Transfer

3.7.3. Other

3.7.3.1 Leak Reduction
3.7.3.1.1 Maintain Machines with a Regular Maintenance Program to Prevent Oil Leaks
3.7.3.1.2 Implement a Regular Maintenance Program to Reduce Emissions from Leaky Valves and Pipe Fittings

3.7.3.2 Other
3.7.3.2.1 Implement a Regular Maintenance Program to Keep Racks and Tanks Free of Rust, Cracks, or Corrosion.
3.7.3.2.2 Apply a Protective Coating to Racks and Tanks
3.7.3.2.3 Implement a Machine and Coolant Sump Cleaning Program to Minimize Coolant Contamination

3.8 Material Changes

3.8.1 Reduce Use of Solvents

3.8.1.1 Minimize Solvent Usage/Maximize Solvent Life
3.8.1.1.1 Maintain Water Separator and Completely Dry Parts to Avoid Water Contamination of Solvent
3.8.1.1.2 Use Deionized Water for Make-up and Rinse Water to Increase Solution Life
3.8.1.1.3 Prevent Excessive Solvent Usage During Cleaning (Operator Training)
3.8.1.1.4 Automate Paint Mixing-Use Compressed Air Blowout for Line Cleaning Prior to Solvent Cleaning

3.8.1.2 Minimize Emissions
3.8.1.2.1 Cover Solvent and Resin Containers to Minimize Evaporative Losses
3.8.1.2.2 Use Tight-Fitting Lids on Material Containers and Solvent Cleaning Tanks to Reduce VOC Emissions
3.8.1.2.3 Use Tight Fitting Lids on Material Containers to Reduce VOC Emission
3.8.1.2.4 Install Floating Covers on Tanks of Volatile Materials to Reduce Evaporation
3.8.1.2.5 Remove Rollers from the Machines and Clean in a Closed Solvent Cleaner

3.8.1.3 Material Replacement
- 3.8.1.3.1 Use Water-Based Adhesives
- 3.8.1.3.2 Use Less Toxic and Volatile Solvent Substitutes
- 3.8.1.3.3 Convert to Aqueous Cleaning
- 3.8.1.3.4 Use Water-Based Cutting Fluids During Machining to Eliminate Need for Solvent Cleaning
- 3.8.1.3.5 Use Low VOC or Water Based Paint
- 3.8.1.3.6 Use Less Toxic Solvents
- 3.8.1.3.7 Use Soy or Water-Based Inks

3.8.1.4 Solvent Recovery
- 3.8.1.4.1 Regenerate Cleaning Solvent On-Site and Reuse
- 3.8.1.4.2 Distill Contaminated Solvents for Reuse
- 3.8.1.4.3 Recycle Cleaning Solvent and Reuse

3.8.2 General

3.8.2.1 Liquid
- 3.8.2.1.1 Use Alternatives for Acids and Alkaline (for example, Water, Steam, Abrasive)
- 3.8.2.1.2 Use Reactive Rinsing to Extend Bath Life
- 3.8.2.1.3 Use Water Based or Greaseless Binders to Increase Wheel Life
- 3.8.2.1.4 Use Non-Phenolic Strippers to Reduce Toxicity Associated with Phenol and Acid Additives
- 3.8.2.1.5 Convert to Aqueous Cleaning System
- 3.8.2.1.6 Convert to Less Toxic Hydrocarbon Cleaners
- 3.8.2.1.7 Replace Hexavalent Chromium Solutions with Trivalent Solutions
- 3.8.2.1.8 Use Cyanide Free Solutions Whenever Possible
- 3.8.2.1.9 Replace Cadmium-based Solutions with Zinc Solutions
- 3.8.2.1.10 Use Water-Based Image Processing Chemicals
- 3.8.2.1.11 Use Water-Based Developers and Finishers

3.8.2.2 Solid
- 3.8.2.2.1 Use Silver Free Films
- 3.8.2.2.2 Use Building Materials Which Require Less Energy to Produce
- 3.8.2.2.3 Alter Raw Materials to Reduce Air Emissions
- 3.8.2.2.4 Purchase High Volume Materials in Returnable Bulk Containers

4. Direct Productivity Enhancements

4.1 TQM (Total Quality Management)

4.1.1 Lower Raw Material Costs

4.1.1.1 Recycling
- 4.1.1.1.1 Market Waste Material as Clean-Up Rags
- 4.1.1.1.2 Sell Combustible Waste or Byproducts as Fuel

4.1.1.2 Volume Discounting
- 4.1.1.2.1 Consider Use of Bulk Materials Where Possible
- 4.1.1.2.2 Purchase Adhesive in Bulk Containers

4.1.2 Administrative

4.1.2.1 Fiscal Management
- 4.1.2.1.1 Purchase Equipment Instead of Leasing

4.1.3 Manufacturing

4.1.3.1 JIT (Just In Time Manufacturing)

4.1.3.2 Minimize Equipment Down Time
4.1.3.2.1 Install An Uninterruptable Power Supply

4.1.3.3 Miscellaneous Operation Enhancements
4.1.3.3.1 Use Only Amount of Packaging Material Necessary
4.1.3.3.2 Optimize Production Lot Sizes and Inventories
4.1.3.3.3 Maintain Clean Conditions Before Painting to Avoid Surface Contamination Resulting in Paint Defects

4.1.3.4 Utilize Available Resources
4.1.3.4.1. Adopt In-House Material Generation

4.1.4 Other

4.1.4.1 Worker Training
4.1.4.1.1 Train Operators for Maximum Operating Efficiency

4.1.4.2 Utilize Available Space
4.1.4.2.1 Expand Operations into Unused Space

Application codes

A suffix is used with the Assessment Recommendation codes listed above in this manual to designate the general area of application of the recommendation. Therefore, a similar strategy applied to a space heating boiler or a process furnace would be distinguishable. The codes are:

Number	Application	Examples
1 Manufacturing Process	Process Heat Recovery, Variable Speed Drives on Process Equipment	Active Cooling of Injection Molds
2 Process Support	Air Compressors, Steam, Nitrogen, Cogeneration	
3 Building and Grounds	Lights, HVAC	
4 Administrative	Taxes, Inventory Control, Sale of Wastes	

Source: *Energy Conservation Program Guide For Industry and Commerce*. 1974. National Bureau of Standards Handbook 115, U.S. Government Printing Office, Washington, DC.

Appendix 3.B

Perfluorocarbon Emissions and Emissions Reductions in the Aluminum Production Industry

Perfluorocarbon Emissions and Emissions Reductions in the Aluminum Production Industry

This appendix presents background information on the aluminum production industry, a brief summary of perfluorocarbon emission reduction options, and a description of related regulations and programs.

B.1 Industry Background

The production of aluminum results in emissions of several greenhouse gases, including carbon dioxide and two perfluorocarbons (PFCs), CF_4 and C_2F_6. (Carbon dioxide emissions are primarily the result of energy inputs used in the production process, typically fossil fuel-derived electricity.) Emissions of these PFCs occur during the reduction of alumina in the primary smelting process.[a] The aluminum production industry is thought to be the largest source of these two greenhouse gases.

Aluminum is produced by the electrolytic reduction of alumina (Al_2O_3) in the Hall-Heroult reduction process. Alumina is dissolved in molten cryolite (Na_3AlF_6), which acts as the electrolyte and is the reaction medium. An electric potential is applied to the cryolite/alumina solution through carbon anodes and cathodes, reducing the alumina to produce molten aluminum. During production, the amount of alumina present slowly decreases as it is reduced to aluminum. Alumina is therefore added on a continual basis to maintain an adequate concentration in the reaction vessel. PFCs can be formed during disruptions of the production process known as anode effects, which are characterized by a sharp rise in voltage across the pot. The PFCs can be produced through two mechanisms: direct reaction of fluorine with the carbon anode, and electrochemical formation. In both cases the fluorine originates from dissociation of the molten cryolite.

In the United States, aluminum is produced by 13 companies at 23 facilities. Total U.S. production was approximately 4 million metric tons in 1990. Other major producing countries include Canada and Australia. Considerable excess capacity exists worldwide, and no new facilities are planned in the U.S.

Because CF_4 and C_2F_6 are inert, and therefore pose no health or local environmental problems, there has hitherto been little study of the magnitude of emissions. The current estimate of the emissions factor for CF_4 emissions during anode effects is 0.003 lb CF_4 per minute per kAmp (1.4×10^{-3} kg/min/kAmp).[b] This emissions factor corresponds to emissions of between 0.3 and 0.9 kg CF_4 per metric ton of aluminum produced. Total U.S. emissions are therefore estimated to range from roughly 1,200 to 3,700 metric tons of CF_4. Emissions of C_2F_6 are estimated to be an order of magnitude lower, and therefore range from 120 to 370 metric tons.

(a) PFCs are not emitted during the smelting of recycled aluminum.
(b) One kAmp, a measure of electric current, is 1000 amps.

Anode effects and the associated production of PFCs do, however, have some impact on smelting efficiencies, and aluminum producers have therefore already begun to develop methods to reduce their occurrence. Anode effects, which may last from less than one to several minutes, result in several operational disadvantages, including the following:

- an incremental loss of electrolytic (process) material
- short-term disruption of the production process
- the need for manual attention to suppress anode effects in non-automated pots, or for anode effects that cannot be suppressed automatically.

In general, anode effects occur when (1) too little alumina is being added to the reaction process, (2) localized fluctuations occur in the current density, or (3) pot temperatures are too low. Anode effects occur for both planned and unplanned reasons. Planned anode effects are induced by the intentional "starving" of alumina from the process, and are used to establish a lower limit of alumina addition, thereby avoiding possible sludging from excess material; these effects are also used to eliminate carbon dust near the anode (which can cause various operational problems). Unplanned causes of anode effects include unintentional reduction of alumina addition, inter-electrode spacing fluctuations, and process temperature drops.

B.2 Emissions Reductions Actions

Practices for reducing emissions of PFCs focus on reducing the frequency and duration of anode effects. In both cases, emission reduction activities will primarily involve operational and management changes. For example, the frequency of anode effects can be reduced by incremental improvements in (1) managing alumina additions and other process parameters, (2) algorithms controlling automated processes, (3) training of personnel, and (4) quality control of anode manufacture to reduce subsequent carbon dust formation. The average duration of anode effects can be reduced by improving the suppression response of potroom[a] personnel.

B.3 Related Regulations and Programs

There are no emissions regulations for CF_4 or C_2F_6 in the United States. However, over the past couple of years, U.S. aluminum producers have begun to take steps to reduce emissions from this source. Aluminum companies are working with the U.S. EPA in a voluntary program to reduce emissions. Because of the relatively limited knowledge concerning the relationship of emissions and operating parameters, one of the first steps being taken is an industry measurement plan. This

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(a) The potroom is the room containing the electrolytic cells used to produce primary aluminum from alumina.

measurement plan will improve estimates of total emissions, will develop better emissions factors for specific operating conditions, and will standardize measurement protocols.

In the future, the voluntary program will provide a flexible mechanism for developing, implementing, and reporting emission reduction efforts. The guidelines for the voluntary reporting of activities under the 1605(b) program are consistent with the continuing development of this program.

B.4 References

U.S. Environmental Protection Agency (EPA). 1993. *Proceedings—Workshop on Atmospheric Effects, Origins, and Options for Control of Two Potent Greenhouse Gases: CF_4 and C_2F_6.* Global Change Division, Office of Air and Radiation, Washington, DC.

Appendix 3.C

Methane Emissions and Emissions Reductions in the Natural Gas Industry

Methane Emissions and Emissions Reductions in the Natural Gas Industry

This appendix presents background information on the natural gas industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

C.1. Industry Background

Methane is the principal component of natural gas; therefore, leaks from the wide variety of components, processes, and activities that make up the natural gas system contribute to methane emissions. In 1990 the U.S. natural gas system accounted for about 10 to 15 percent of U.S. methane emissions, or about 2.2 to 4.3 Tg per year, with a central estimate of about 3.0 Tg [a] per year (USEPA 1993a). In the absence of efforts to reduce emissions, methane emissions from the natural gas industry are expected to increase by about 10 to 25 percent over the next 20 years as the size of the industry and the amount of gas handled increases (USEPA 1993a).

Based on an array of available technologies, it is technically feasible to reduce methane emissions from the natural gas system by about 33 percent (USEPA 1993b). Some of these technologies are estimated to be profitable: the value of the gas emissions avoided exceeds the costs of implementing the technology. Using these profitable technologies, methane emissions from natural gas systems can be reduced profitably by about 25 percent (USEPA 1993b). This estimate of the potential for profitable methane reductions reflects the continued development of new technologies in the natural gas industry.

The main barriers to realizing these emission reductions are informational and regulatory. Information regarding the profitability of the options for reducing emissions must be disseminated. In some cases the technologies are relatively new, and their operating characteristics and costs are not widely known. Rate regulations also pose a barrier because in some cases companies are able to recover the cost of lost gas from customers, so that the incentive for avoiding emissions is substantially reduced.

C.1.1 Industry Structure

The U.S. natural gas system is composed of a complex interconnected set of facilities that can be divided into the following main segments:

- **Production**. Gas is withdrawn from underground formations using on- and off-shore wells, frequently in conjunction with oil. Gathering lines are generally used to bring the crude oil and raw gas streams to one or more collection points within a production field where the gas is separated and dried, often using glycol dehydrators.

(a) Tg = Teragram = 1 million metric tons.

- **Gas processing**. Natural gas is usually processed in gas plants to remove water, oil, hydrogen sulfide, and heavier hydrocarbons (that is, condensate) from the gas. The processed gas is injected into the natural gas transmission system.

- **Transmission pipelines**. Transmission facilities transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to distribution centers or large-volume customers. In addition to the large-diameter high-pressure pipelines, these facilities include metering stations, maintenance facilities, and compressor stations.

- **Storage and injection/withdrawal facilities**. During periods of low (high) gas demand, natural gas is injected into (withdrawn from) underground storage reservoirs. The storage and injection/withdrawal facilities include a variety of processes and equipment, including compressors, wells, separators, and dehydrators.

- **Distribution Systems**. Distribution systems are extensive networks of generally small-diameter, low-pressure pipelines. Gas enters distribution networks from transmission systems at "gate stations," where the pressure is reduced for distribution within cities or towns. Pressure regulating and metering facilities are located throughout the distribution system.

While firms in the natural gas industry vary significantly in size and breadth of services, a relatively small number of large firms dominate. Within the distribution segment, which has over 300 private and public owned entities, 20 firms serve about half of all natural gas customers and account for about half of all distribution main mileage (Watts 1989; AGA 1991). Similarly, while there are over 100 transmission companies, 20 companies account for nearly two-thirds of the total transmission and gathering system pipeline mileage (Watts 1989; AGA 1991).

Although the production and processing sectors include a number of large firms, including the major oil companies, these sectors are less concentrated than the other sectors of the industry. More than 250,000 gas wells and over 275,000 oil wells market gas, and over 700 gas processing facilities. Although there are a few large processing plants, the processing segment is not dominated by a small number of large facilities.

The breadth of services offered by companies in the gas industry also varies. *Integrated* gas companies obtain gas operating revenues from both retail gas distribution and gas transmission.[a] *Distribution* and *transmission* companies obtain their gas operating revenues almost exclusively from distribution or

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(a) Examples of integrated companies: Southern California Gas; Lone Star Gas; Michigan Consolidated Gas; and Arkla, Inc.

transmission activities, respectively.[a] Finally, there are *combination* companies that supply both gas and another utility, such as electricity or water.[b]

C.1.2 Methane Emissions

In 1990 about 3 Tg of methane was emitted from the diverse set of facilities that comprise the natural gas system (USEPA 1993a). The emissions can be divided into the following three main types:

- **Normal operations** including compressor engine exhaust emissions, emissions from pneumatic devices,[c] and fugitive emissions (that is, small chronic leaks from components designed to store or convey gas and liquids)

- **Routine maintenance** including equipment blowdown and venting, well workovers, and scraper (pigging) operations

- **System upsets** including emissions due to sudden, unplanned pressure changes or mishaps.

Fugitive emissions across all segments of the system are estimated to be the largest individual source of emissions, accounting for about 38 percent of the estimated total. Pneumatic devices are the second largest individual source, accounting for approximately 20 percent of the total estimated emissions. Methane emitted in engine exhaust (principally reciprocating engines used to drive pipeline compressors) is the third largest source of emissions. Together, fugitive emissions, pneumatic devices and engine exhaust account for nearly 75 percent of total estimated methane emissions from the U.S. natural gas system (USEPA 1993a). Table C.1 summarizes the emissions by industry sector and emissions type.

As shown in Table C.1, considerable uncertainty remains regarding current estimates of emissions. While a great deal of progress has been made in quantifying emissions, more work is warranted in some areas. A joint research program sponsored by the Environmental Protection Agency and the Gas Research Institute (GRI) is collecting data to improve the emissions estimates.

(a) Examples of distribution companies: Northern Illinois Gas; Brooklyn Union Gas; and Atlanta Gas Light. Examples of transmission companies: Northern Natural Gas; El Paso Natural Gas; and Columbia Gas Transmission.
(b) Examples of combination companies: Pacific Gas and Electric; Public Service Electric and Gas Company; Consolidated Edison Company of New York, Inc.
(c) Pneumatic devices, used primarily in the production and transmission segments, use compressed gas as a source of energy. The compressed natural gas in the pipeline is often used, and hence, the devices release small amounts of gas as part of their normal function.

Table C.1. Methane Emissions From the U.S. Natural Gas System (Tg/yr)

Emissions Type	Field Production	Processing	Injection/ Withdrawal	Transmission	Distribution	Engine Exhaust	Total
Normal Operations							
Pneumatic devices	0.43[c]	0.00	<0.001	0.20	NE	—	0.63
range	(0.17 - 1.3)	(0.00 - 0.00)		(0.08 - 0.6)			
Dehydrator Vents	0.11	0.04	NE	0.03	NE	—	0.18
range	(0.04 - 0.33)	(0.02 - 0.12)		(0.01 - 0.09)			
Fugitive emissions	0.39	0.01	<0.001	0.43	0.29	—	1.12
range	(0.15 - 1.17)	(0.00 - 0.03)		(0.17 - 1.29)	(0.12 - 0.87)		
Engines Exhaust:	—[d]	—	—	—	—	0.41	0.41
range						(0.27 - 0.64)	
Engine Other[a]	0.02	0.03	0.01	0.07	NE	—	0.13
range	(0.01 - 0.06)	(0.01 - 0.09)	(0.00 - 0.03)	(0.03 - 0.21)			
Other[b]	0.02	<0.01	<0.001	0.05	NE	—	0.07
range	(0.01 - 0.06)			(0.02 - 0.15)			
Routine Maintenance	0.07	<0.01	0.01	0.22	<0.01	—	0.32
range	(0.03 - 0.21)		(0.00 - 0.03)	(0.09 - 0.66)			
Systems Upsets	0.04	<0.001	<0.01	0.03	0.04	—	0.11
range	(0.02 - 0.12)			(0.01 - 0.09)	(0.02 - 0.12)		
Total 1990 Methane Emissions	1.08	0.09	0.02	1.03	0.33	0.41	2.97
range	(0.43 - 3.24)	(0.04 - 0.27)	(0.01 - 0.06)	(0.41 - 3.09)	(0.13 - 0.99)	(0.27 - 0.64)	(1.70 - 5.95)

(a) Includes emissions from compressor station blowdowns, compressors starts/stops and compressor scrubber operations.
(b) Includes inlet flare activity, emissions due to orifice changes and scrubber operations at metering stations and pipelines.
(c) Includes emissions from heaters, separators, gas dehydrators and gathering pipelines.
(d) Emissions from engine exhaust are estimated separately.
NE-Not estimated, emissions are believed to be negligible.

Source: USEPA (1993b).

C.2 Technologies for Reducing Emissions

C.2.1 Currently Available Technologies

Through the more widespread use of a variety of technologies and practices, which are currently available and have been shown to be cost-effective in a number of settings, methane emissions from the U.S. natural gas system can be reduced profitably by about 0.8 Tg and 0.9 Tg in 2000 and 2010, respectively (USEPA 1993b). These emission reductions are equivalent to about 18 million metric tons of carbon dioxide.[a] Furthermore, reducing emissions saves gas that would otherwise be wasted, thus producing annual energy savings equivalent to 0.83 Tg[b] of natural gas.

The emissions reduction options identified and evaluated by USEPA (1993b) include the following:

- Production and processing:
  - *Pneumatic devices* are used throughout gas production on heaters, separators, gas dehydrators, and gathering pipelines. Their operation results in intentional releases of methane. Options to reduce emissions from these devices include replacing high-bleed pneumatics at the end of their useful life with low- or no-bleed designs where technically appropriate. This is a very cost-effective option for production facilities, and could reduce methane emissions by about 0.24 Tg/yr in 2000.
  - *Gas dehydrators* remove moisture from the gas stream. Glycol is generally used to absorb the moisture. When the glycol is regenerated, water vapor, methane, and volatile organic compounds (VOCs) are emitted. The principal option for reducing these methane emissions is to install a flash tank separator and use the recovered methane for fuel in the glycol regeneration boiler. This option is generally cost effective and could reduce emissions by about 0.12 Tg/yr in 2000. This option may be required in states, such as Louisiana and California, that are developing programs to reduce toxic air emissions from gas dehydrators.
  - *Fugitive emissions* are unintentional and are usually continuous releases associated with leaks caused by a failure that breaches the integrity of the system, such as a damaged seal or corroded pipeline. The primary option for reducing fugitive emissions is the implementation of

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(a) This estimate of equivalent carbon dioxide emissions assumes a global warming potential (GWP) of 22 for methane which is consistent with IPCC (1992). However, significant uncertainty remains in methane's GWP, and if a different value is chosen, the estimate of the carbon dioxide-equivalent emissions would need to be modified accordingly.

(b) 1 Tg of methane is approximately 52 billion cubic feet of gas (one cubic foot of gas has about 19.2 grams of methane at 1 atmosphere and 60°F).

directed inspection and maintenance (I/M) programs. While this option could reduce methane emissions by about 0.19 Tg/yr in 2000, the cost of the program exceeds the value of the gas saved, and is consequently not considered profitable.

- Gas transmission:

  - *Fugitive emissions* in the transmission stage are associated with leaks from pipeline corrosion and inadequately sealed valves, fittings, and assemblies. These components are concentrated at compressor stations, which alone account for about 75 percent of the fugitive emissions from this stage. The primary option for reducing these fugitive emissions is the implementation of directed inspection and maintenance (I/M) programs at compressor stations. This option is cost effective, and could reduce methane emissions by about 0.24 Tg/yr in 2000.

  - *Pneumatic devices* are also used throughout the transmission stage. Replacing high-bleed pneumatics at the end of their useful life with low- or no-bleed designs where technically appropriate throughout this stage is very cost-effective. By replacing the high-bleed devices, methane emissions can be reduced by about 0.12 Tg/yr in 2000.

  - *Reciprocating engines* are used throughout the industry to drive compressors that transport gas, but are most highly concentrated in the transmission stage. In 1990, reciprocating engines in the transmission stage were estimated to emit about 0.18 Tg/yr. The major option for reducing emissions from reciprocating engines involves the greater use of turbine engines for compression in transmission pipelines, as new transmission lines are constructed and as old reciprocating units are replaced. This option could reduce emissions by about 0.07 Tg/yr in 2000 and 0.13 Tg/yr in 2010. However, many operational factors must be considered when choosing between turbines and reciprocating engines, and this choice must be made site by site.

  - *Venting during routine maintenance* of pipelines occurs when the natural gas must be removed from a section of pipe for safety reasons during repairs. Options for reducing these emissions include using portable evacuation compressors (PECs) to pump the gas from the section of pipe to be repaired to an adjoining section. The utilization of PECs could reduce emissions by about 0.02 Tg/yr in 2000. While this technology has been used cost effectively in Canada, differences in pipeline design and operations between the two countries cause this technology not to be cost effective in the United States with current gas prices.

- Gas distribution:

  - *Fugitive emissions from gate stations* are an important source of methane from distribution systems. These emissions may be reduced through implementation of directed inspection and maintenance programs. This option is cost effective and could reduce methane emissions by about 0.10 Tg/yr in 2000.

- *Fugitive emissions from subsurface piping* are an important source of methane emissions in the distribution system. These emissions are reduced when pipeline segments are rehabilitated, either through complete replacement of the leaking pipe or joint, or through insertion of repair materials into the old pipe. According to Watts (1990), for every two miles of main or service pipeline added in the late 1980s, about one mile of existing line was replaced, usually with plastic. The costs for these repairs generally far exceed the value of saved gas and are justified principally on the basis of reducing potential safety hazards to the public.

C.2.2 Emerging Technologies for Reducing Emissions

A number of new or improved technologies and practices for reducing methane emissions are being developed. These emerging technologies address emissions from each stage of the U.S. gas system. In many cases, these technologies are already being field tested, or are in limited use, and it is expected that they will be used more extensively in the near future. The technologies identified in USEPA (1993b) as most likely to have an impact on efforts to reduce emissions include the following:

- Installing catalytic converters on reciprocating engines
- Using "smart" regulators in distribution systems
- Using metallic coated seals
- Using sealant and cleaner injections in valves
- Using composite wraps for pipeline repair.

C.3 Relationship to Existing Regulations and Programs

C.3.1 EPA's Natural Gas STAR Program

The Natural Gas STAR Program is a voluntary agency-industry initiative to reduce methane emissions. Its objectives are to promote the implementation of cost-effective technologies and practices that reduce methane emissions; and encourage the development and implementation of new technologies and practices that can further reduce emissions or lower the cost of reducing emissions. Those companies that agree to participate sign a Memorandum Of Understanding (MOU) outlining the responsibilities of each party. Under the MOU, the company agrees to implement and report on cost-effective Best Management Practices (BMPs) and technologies.

In addition to the BMPs, other practices that reduce emissions undertaken by the company may also be conducted under the Natural Gas STAR Program. The company would provide verification that the emission reduction was achieved. Based on this additional information provided by companies participating in the program, new BMPs may be added to the program, and information describing new opportunities for reducing emissions will be disseminated.

An initial implementation plan must be prepared by each company, describing how it proposes to reduce emissions. Annual reports are required subsequently to document progress toward reducing emissions. The annual reports, a fundamental part of the program, describe the actions taken by the companies, the costs incurred, and the emissions reductions achieved. The reporting system is being developed so that it does not duplicate existing reporting under Department of Transportation (DOT) safety programs (see below).

To facilitate reporting, standard methods have been developed for estimating emissions reductions associated with the BMPs. In addition, provisions are included for updating and improving the emissions reductions estimates as new information becomes available. Each company makes its own estimates of emissions reductions achieved, which are reviewed by EPA. The EPAct Section 1605(b) reporting guidelines described here are designed so that the annual reports prepared under the Natural Gas STAR Program can be used as the basis for estimating and reporting emissions reductions.

For its part, EPA agrees to remove any unjustified regulatory barriers to implementing the BMPs, and to reduce the costs and risks, if any, of high efficiency/low emissions devices and technologies. EPA is also developing training courses which describe the technical and economic characteristics of the BMPs. Both EPA and the Natural Gas STAR Partners (that is, the companies) agree to publicize the program's participation and membership to increase the awareness of the capability of the program.

To date, transmission companies representing about 25 percent of the U.S. transmission system have joined the program. In the distribution segment, companies have joined that serve about 25 percent of the natural gas customers in the United States.

C.3.2 Other Existing Regulations and Programs

Several key programs and initiatives affect methane emissions from the U.S. natural gas system and efforts to reduce emissions. The Office of Pipeline Safety (OPS) of the Department of Transportation (DOT) implements a program of minimum Federal safety standards for the transportation of natural gas by pipeline. The programs in California that go beyond the Federal safety requirements to reduce fugitive emissions of reactive organic gases (ROGs) from oil and gas production sites also reduce methane emissions. Methane emissions will also be reduced by the initiatives underway to reduce toxic emissions from glycol dehydrators used to dry natural gas.

C.3.2.1 Federal Safety Standards and Reporting Requirements

To prevent the incidence of death, personal injury, or property damage that may arise from the release of gas from pipelines or gas facilities, the OPS implements a program of safety requirements that regulates the quality of materials used in the gas system, the design and installation of components; leak prevention and maintenance measures; and operating procedures.[a] As a companion to these safety requirements, OPS has promulgated annual and incident reporting requirements under 49 CFR Part 191.

The annual reports required by OPS contain substantial information about the facilities that comprise natural gas transmission and distribution systems. As with EPA's Natural Gas STAR Program, the reporting guidelines do not duplicate the information that is already reported to OPS.

C.3.2.2 California Directed I/M Programs

Directed inspection and maintenance (I/M) programs have been mandated at oil and gas production and processing facilities, chemical plants, and pipeline transfer stations in several air quality management districts in California. By implementing the programs, these facilities have reduced ROG emissions by about 40 to 70 percent. Methane emissions are also reduced.

Several directed I/M programs have been implemented. The programs typically require a facility to inspect all accessible components once every three months and all inaccessible components once every year. The inspection frequency of pumps, compressors, and pressure relief valves varies among programs from once every 8 hours to daily or weekly inspections. To inspect components for leaks, a hydrocarbon analyzer such as an Organic Vapor Analyzer (OVA) is used to measure the concentration of hydrocarbons close to the component. A reading greater than a specified threshold value, usually 10,000 ppm, indicates that the component is leaking.

Leaking components must be repaired or replaced within a specified time period (typically 1 day to 3 weeks) which varies among districts and by component type and rate of emissions. After a component is repaired, it is reinspected to verify that the component is no longer leaking. Reinspection

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(a) The OPS regulations specify the minimum requirements for the materials and design of pipeline, pipeline components, transmission lines and mains, customer meters, service regulators and service lines. General construction requirements for welding include the use of qualified personnel and the testing of weld with destructive and non-destructive tests. Preventive and maintenance measures include corrosion control and regular leak surveys and strength tests. Operating procedures include damage prevention plans, emergency plans and the investigation of failures. See 49 CFR Part 192.

typically is required within of 1 week to 3 months. In addition, directed I/M programs typically require facilities to physically identify all components and tag leaking components. Records of components, inspections, leaks, and repairs must also be maintained (ARB 1991).

To further reduce fugitive ROG emissions, the California Air Resources Board (ARB) has developed a more stringent I/M program proposal. If the ARB I/M recommendations were adopted by all districts in the state, the more stringent I/M program could reduce fugitive ROG emissions from oil and gas production facilities by an additional 25 percent from current emissions levels (ARB 1991).

The reporting required under the I/M programs designed to date appears to include the information needed to satisfy the reporting requirements of the Natural Gas STAR Program as well as the voluntary reporting guidelines.

C.3.2.3 Glycol Dehydrator Emissions Controls

Glycol dehydrator vents are an important source of methane emissions from the production stage of the natural gas system. Several new permitting requirements and state programs are being initiated to control air toxic emissions from glycol dehydration vents, which include emissions of benzene, toluene, ethyl benzene, and xylene isomers, collectively referred to as BTEX.

Several states have initiated local programs to control BTEX emissions, including Oklahoma and Louisiana (Pees and Cook 1992; Starrett 1992). The Clean Air Act (CAA) Amendments of 1990 will significantly impact many glycol dehydration units in the next few years. Under Title III of the Amendments, a glycol dehydration unit, or a group of glycol dehydration units located within a contiguous area and under common control, which emits 10 tons per year of any one of 189 listed hazardous air pollutants (HAPs) or 25 tons per year of any combination of HAPs is considered a major source of air contamination. Such a source will be subject to regulation under the CAA which will include implementation of maximum achievable control technology to control emissions of HAPs. All new and existing major sources will be required to obtain a permit to operate. An operating permit will be valid for a limited period and will include specific limits and conditions that assure compliance with all applicable requirements and standards (Falzone 1992).

These requirements are expected to lead to the collection and combustion of emissions from many of the largest glycol dehydrators. As a consequence, the methane emitted will also be burned. The BTEX requirements will likely be implemented through permit programs. The information developed to comply with the BTEX requirements is expected to be adequate for the reporting guidelines under EPAct Section 1605(b).

C.4 References

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Appendix 3.D

Methane Emissions and Emissions Reductions in Landfills

Methane Emissions and Emissions Reductions in Landfills

This appendix presents background information on the landfill industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

D.1 Industry Background

Landfills are the largest anthropogenic source of methane emissions in the United States. In 1990 landfills emitted an estimated 8.1 to 11.8 Tg[a] to the atmosphere. In the absence of efforts to reduce emissions, landfill methane emissions are expected to grow to between 9.5 and 13.4 Tg per year by 2010 (USEPA 1993a).

It is technically feasible to recover up to 85 percent of the methane produced by landfills by drilling wells into the landfills and withdrawing the landfill gas. The estimate of 85 percent is higher than the average landfill gas collection efficiency estimated for existing recovery projects (75 percent) but is achievable with current technology. The extent of reduction that is technically feasible varies among landfills and depends on site-specific design and waste factors.

The potential profitability of the recovery of the gas is very sensitive to the price at which landfills can sell electricity produced from the gas. At an electricity price of $0.05 per kWh, it is potentially profitable to recover only about 50 to 60 percent of landfill methane emissions. At a price of $0.04 per kWh it is potentially profitable to recover only about 10 to 15 percent of emissions, and at a price of $0.06 it is potentially profitable to recover about 65 to 75 percent of emissions (USEPA 1993b).

The main barriers to recovering landfill gas are economic, informational, and institutional barriers. These include low electricity prices, perception of high risk, and siting and permitting concerns.

D.1.1 Industry Structure

Sanitary landfills have been used widely since the early 1970s, and today landfills receive over 70 percent of the solid waste generated in the United States (USEPA 1990). Although an estimated 6,000 landfills emit methane in the United States, about 1,300 account for nearly all the methane emitted. The amount of methane generated per quantity of refuse disposed depends primarily on the amount of refuse in place in the landfill, refuse characteristics, and moisture. Consequently, of these 1,300

(a) Tg = Teragram = 1 million metric tons landfills, about 900 landfills account for 85 percent of the waste in landfills and 75 percent of the methane emitted. The 19 largest landfills account for about 25 percent of the waste in landfills and 20 percent of the total methane generated.

D.1.2 Methane Emissions

Because about 70 percent of the waste placed in landfills is organic material, the potential for methane production is great. As shown in Table D.1, U.S. landfill methane emissions in 1990 are estimated to range from about 8.1 to 11.8 Tg/yr, or about 37 percent of total U.S. methane emissions.

Despite the efforts underway to divert waste from landfills, changes in waste disposal practices will not significantly reduce U.S. methane emissions over the next 20 years. Based on the analyses in USEPA (1993a), although the rate of waste disposal in landfills is expected to remain fairly constant over the next 20 years, the amount of waste in landfills that can produce methane is expected to increase from about 4,700 million megagrams (10^6 Mg) in 1990 to 5,300 million Mg by 2000 and 5,700 million Mg in 2010. Consequently, even after considering changes in waste disposal practices, methane emissions from landfills may increase from current levels over the next 20 years. Emissions in the years 2000 and 2010 are estimated to be about 9 to 13 Tg/yr (USEPA 1993a).

D.2 Technologies Available for Reducing Emissions

D.2.1 Currently Available Technologies

There are two general approaches for reducing methane emissions from landfills. One approach involves modifying waste management practices to reduce the amount of waste landfilled. By diverting waste away from landfill disposal and toward other waste disposal methods such as recycling, less waste will be in landfills to produce methane in the future. Another approach is to recover the methane and to use it as an energy source or to flare it. Utilizing or flaring the methane is the only method currently available for reducing emissions from existing landfills and from landfills that will contain degradable waste in the future.

It is technically feasible to recover up to 85 percent of the methane produced by landfills by drilling wells into the landfills and withdrawing the landfill gas. Most gas collection systems have the following design. After the landfill is capped, vertical wells consisting of perforated pipe casing are drilled into the landfill. These wells are back filled with permeable material such as gravel around the casing and are sealed at the surface with an impermeable material to prevent the inflow of air. The wells are connected by horizontal piping to a central point where a motor/blower provides a vacuum to remove the gas from the landfill. Once collected, the gas can be used to generate electricity or to sell as a medium-BTU fuel to fire industrial boilers, chillers, or similar equipment. In cases where it may not be economical to use the gas, the best alternative is to flare it.

Table D.1 - National Methane Emission Estimates for 1990[(a)]

Landfill Size Distribution by Waste in Place						National Emissions (Tg/Yr)	
Size Class	Range: Low (Mg)	Range: High (Mg)	Number Landfills	Waste in Place (10^6 Mg)	Percent of Total Waste	Low	High
1 (Closed)	0	500,000	3,000	negligible	<0.5%		
2	0	500,000	4,744	494	10.5%	1.01	1.66
3	500,000	1,000,000	425	312	6.6%	0.63	1.05
4	1,000,000	5,000,000	712	1,581	33.6%	3.59	6.15
5	5,000,000	10,000,000	106	709	15.1%	1.35	1.85
6	10,000,000	20,000,000	27	411	8.8%	0.69	0.98
7	20,000,000	200,000,000	19	1,194	25.4%	1.78	2.73
Total[(b)]			6,034	4,700	Methane Generation	9.80	13.60
					Minus Recovery	1.50	1.50
					Plus Industrial	0.69	0.95
					Minus Oxidation	0.90	1.31
					Net Emissions for 1990	8.09	11.75

(a) Emission estimates from USEPA (1993a); landfill size distribution information based on USEPA (1987).
(b) Totals do not include size class 1.

Source: USEPA (1993b).

Electric power generation is the most common gas utilization method for landfill gas recovery projects. According to the *Methane Recovery From Landfill Yearbook, 1990-91*, compiled by Government Advisory Associates (GAA), Inc., over two-thirds of the gas-to-energy projects generate or plan to generate electricity. The most common options for producing electricity are the use of internal combustion engines and turbines.

Sale of gas as a medium-BTU fuel[(a)] is possible if the landfill is located close to suitable industrial facilities to which the gas can be transported via pipeline. An ideal medium-BTU gas customer would be located near the landfill and would have a nearly continuous demand for gaseous fuel. Landfill gas customers may use the gas to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating.

Flaring is the simplest way to eliminate landfill gas. The advantage of flaring is that the capital cost is small compared to energy recovery systems. The disadvantage is that flaring produces no income for the landfill.

In 1990, approximately 100 landfill gas recovery projects recovered approximately 1.5 Tg of methane, or about 10 to 15 percent of the methane generated by landfills. At that time, about 50 additional projects were in the planning stages. In 1991, of the just over 100 landfill gas recovery and utilization projects, 71 generated electricity and 25 sold the gas as a medium-BTU fuel. Three landfills both produced electricity and sold the gas as a medium-BTU fuel. Of the 74 landfills that produced electricity, most have an electrical generating capacity between 0.5 and 4 megawatts (GAA 1991).

D.2.2 Emerging Technologies for Reducing Emissions

A number of new or improved technologies for utilizing landfill gas are being developed. In many cases, these technologies are already being field tested or are in limited use, and they are expected to be used more extensively in the near future. The technologies identified in USEPA (1993b) include production of liquid fuels and industrial chemicals from landfill gas and fuel cells.

Fuel cells in particular may be an attractive option for utilizing landfill gas because they have very low NO_x emissions, which is important in many areas where landfills are located.

D.3 Related Regulations and Programs

D.3.1 Landfill Rule

The USEPA has recently proposed a rule that would indirectly control methane emissions by regulating air pollution emissions from landfills. This proposed rule is the Standards of Performance for New

(a) The energy content of a medium-BTU fuel is about 400-600 BTU/ft^3. The energy content of a high-BTU fuel, such as natural gas, is about 1,000 BTU/ft^3.

Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste (MSW) (USEPA 1991). The purpose of the rule is to limit air pollution from new and modified MSW landfills by requiring them to install gas collection systems and combust the captured landfill gas (with or without energy utilization) if their air pollution emissions exceed a specified cutoff level.

The proposed rule requires any facility with maximum design capacity of 100,000 Mg (111,000 tons) or more to calculate periodically its annual non-methane organic compound (NMOC) emission rate. Each facility where the calculated emission rate is found to exceed the proposed cutoff will be required to install a "well designed gas collection system and one of several effective control devices to either recover or destroy the collected landfill emissions." The control device will have to be capable of reducing NMOCs in the collected gas by 98 percent by weight, thereby meeting EPA's Best Demonstrated Technology (BDT) standards. When finalized, this rulemaking should have a significant impact on landfill gas emissions.

The steps undertaken to comply with this rule will reduce methane emissions. The emissions reductions may be reported as described above. If the landfill flares the gas to comply with the rule, it would need to measure the amount of methane flared in order to have the information needed to report the emissions reductions.

D.3.2 Landfill Outreach Program

Under the Climate Change Action Plan,[a] the U.S. EPA is developing the Landfill Outreach Program to promote the use of cost-competitive techniques for reducing methane emissions from landfills. In addition to addressing landfills affected by the proposed rule limiting air pollution from MSW landfills, the Program is focusing on landfills that will not likely be affected by the rule. As a result of the Program, additional landfills are expected to recover and utilize landfill gas. Activities taken in response to this program may be reported under Section 1605(b).

D.4 References

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(a) The Climate Change Action Plan, put forward by the Federal Government in October 1993, aims to address the challenge of global warming with cost-effective emission reduction initiatives. The goal of the Plan is to return U.S. greenhouse gas emissions to 1990 levels by the year 2000.

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Appendix 3.E

Methane Emissions and Emissions Reductions in Coal Mining

Methane Emissions and Emissions Reductions in Coal Mining

This appendix presents background information on the coal mining industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

E.1 Industry Background

Methane (CH_4) and coal are formed together during coalification, a process in which biomass is converted by biological and geological forces into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Deep coal seams have a substantially higher methane content than shallow coal seams, in part because geological pressure intensifies with depth and prevents increasingly larger amounts of methane from escaping. Methane is released when pressure within a coalbed is reduced, through natural erosion, faulting, or mining. Per ton of coal extracted, underground mines release substantially more methane than surface mines.

In 1990, U.S coal mines accounted for about 17 percent of U.S. methane emissions, or about 3.6 to 5.7 Tg[a] per year (USEPA 1993a). In the absence of efforts to reduce emissions, methane emissions from coal mining are expected to increase to 5.0 to 8.7 Tg over the next 20 years primarily due to the projected increased in total U.S. coal production (USEPA 1993a).

Based on an array of available technologies, it is technically feasible to reduce methane emissions from coal mining by about 40 percent (USEPA 1993b). Some of these technologies are estimated to be profitable: the value of the methane recovered exceeds the costs of implementing the technology. Using the profitable technologies, methane emissions from natural coal mining can be reduced by about 30 percent (USEPA 1993b).

The main barriers to realizing these emission reductions are legal and informational. Unresolved legal issues concerning the ownership of coalbed methane resources have constituted one of the most significant barriers to coalbed methane recovery. Ambiguity in certain state legal systems provides a disincentive for investment in coalbed methane projects because of the uncertainties as to which parties may demand compensation for development of resources. This barrier may be partially alleviated as a result of provisions in the Energy Policy Act of 1992, mandating that states must adopt provisions to address coalbed methane ownership issues. In addition to ownership concerns, certain conditions and characteristics of the coal mining industry, including market uncertainty, preferences for investments in coal mine productivity and the relative newness of the concept of utilizing methane from coal mines, may deter methane recovery. Dissemination of information regarding the profitability of the options for reducing emissions would assist in alleviating this barrier.

(a) Tg = Teragram = 1 million metric tons.

E.1.1 Industry Structure

In 1991, of the just over 3,000 operating coal mines in the United States, about 1,500 were underground mines and 1,500 were surface mines. Of these mines, only 210 produced more than one million tons of coal per year. These large mines accounted for about 65 percent of all coal mined in the United States (DOE/EIA 1992).

Based on 1988 data, analysts estimate that in 1990, there were roughly equal numbers of surface and underground mines, and surface mines accounted for 60 percent of total coal produced in the United States. While underground mines accounted for 40 percent of production, they accounted for over 70 percent of methane emissions. Moreover, 200 large and gassy underground mines accounted for over 95 percent of all methane emissions from underground mines (DOE/EIA 1993).

While coal companies vary significantly in size, a relatively small number of large firms own a majority of the large mines, and, thus, account for a large portion of U.S. coal production. In 1991, the top 12 firms (each of which produced more than 20 million tons per year) accounted for over 40 percent of all U.S. production (DOE/EIA 1993).

E.1.2 Methane Emissions

In 1990, an estimated 3.6 to 5.7 Tg of methane was emitted as a result of coal mining activities in the U.S. (Table E.1). The emissions can be divided into three main types: (1) emissions from underground mines, (2) emissions from surface mines, and (3) post-mining emissions.

Underground mining

Underground mines accounted for more than 70 percent of total methane emissions from coal mining in 1988. They will also contribute significantly to emissions in the future. About 55 to 80 percent of the methane liberated by underground coal mines in the U.S. in 1988 was emitted to the atmosphere from ventilation air shafts. Because this methane is contained in air at very low concentrations (less than 1 percent), there are few uses for it. Ventilation air streams will continue to represent a significant portion of methane emissions from underground coal mines in the future.

In 1988, an estimated 0.7 to 1.8 Tg of methane was recovered by degasification systems at U.S. coal mines. These systems, which are used as a supplement to ventilation systems at gassy mines, are in use at about 30 U.S. coal mines. Degasification systems, which recover methane before, during, or after mining, recover methane in concentrations ranging from 30 to over 95 percent. In 1988, six U.S. mines sold the methane produced by degasification systems to local pipeline companies, and as a result about 0.25 Tg of this methane was not emitted into the atmosphere. Currently, 11 mines are recovering methane for pipeline sales.

Table E.1. Annual Methane Emissions from Coal Mining

Key Source	Estimated Range of Emissions (Tg)
Underground Coal Mines:	
Ventilation Systems	2.1
Degasification Systems[(a)]	0.5 - 1.6
Surface Coal Mines	0.2 - 0.7
Post-Mining	0.5 - 0.8
TOTAL (1988)	3.3 - 5.2
TOTAL (1990)[(b)]	3.6 - 5.7

(a) Does not include an additional 0.25 Tg recovered from coal mines in Alabama and Utah that is currently sold to pipelines instead of being vented to the atmosphere.
(b) The 1990 emissions estimate was extrapolated from the 1988 estimate; 1988 is the latest year for which complete data is available.

Source: USEPA 1993a

Annual emissions from degasification systems at underground mines could increase significantly in the future, possibly reaching 0.6 to 2.1 Tg in 2000 and 0.9 to 2.9 Tg in 2010. If key barriers to methane recovery are removed, much of this gas could potentially be recovered profitably instead of being emitted to the atmosphere.

Surface mining

Methane emissions per ton of coal mined are low for surface mined coals. Given the large coal production at U.S. surface mines, however, this emissions source is significant. In 1988, surface mining emissions were an estimated 0.2 to 0.7 Tg.

Post-mining

Some methane remains in the coal after it has been mined and can be emitted during transportation, storage, and handling of the coal. Post-mining emissions in the United States are estimated to be approximately 25 to 40 percent of the in-situ methane content of the coal, or about 0.5 to 0.8 Tg in 1988.

As shown in Table E.1, considerable uncertainty remains regarding current estimates of emissions. While a great deal of progress has been made in quantifying emissions, more work is warranted in some areas.

E.2 Technologies Available for Reducing Emissions

E.2.1 Currently Available Technologies

Through the more widespread use of a variety of technologies and practices, which are currently available and which have been shown to be cost effective in a number of settings, annual methane emissions from U.S. coal mines can be reduced profitably by about 1.0 to 2.2 Tg in 2000 and 1.7 to 3.1 Tg in 2010 (USEPA 1993b). These emission reductions are equivalent to about 20 to 40 million metric tons of carbon dioxide.[a] Furthermore, reducing emissions saves gas that would otherwise be wasted, thus producing annual energy savings equivalent to 1 to 2.2 Tg of natural gas.[b]

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects. Several well-established methods may be used to recover methane. These methods have been developed primarily in order to supplement mine ventilation systems, which ensure that methane concentrations in underground mines remain within safe tolerances (methane is explosive at concentrations of 5 to 15 percent in air). While these degasification systems are currently used for safety reasons, they can also recover methane that may be utilized as an energy source. The purity of the gas that is recovered partially depends on the recovery method and has important implications for the utilization method that can be employed.

To understand how to report emissions reductions achieved by recovering coal mine methane, some background on the recovery techniques themselves is required. In brief, the following are the major approaches for recovering and utilizing coal mine methane.

- **Advance (pre-mining) degasification**. With this method, vertical wells are drilled into the coal seams several years in advance of mining. Depending on the length of time that the wells are in place, the majority of the methane that would otherwise be emitted to the atmosphere when the coal was extracted can be recovered before mining begins. For example, from 50 to over 70 percent of the methane that would otherwise be emitted during mining is likely to be recovered when vertical degasification wells are drilled more than 10 years in advance of mining. One important advantage of this recovery method is that a nearly pure methane can be

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(a) This estimate of equivalent carbon dioxide emissions assumes a global warming potential (GWP) of 22 for methane which is consistent with IPCC (1992). However, significant uncertainty remains in methane's GWP, and if a different value is chosen, the estimate of the carbon dioxide-equivalent emissions would need to be modified accordingly.
(b) 1 Tg of methane is approximately 52 billion cubic feet of gas (one cubic foot of gas has about 19.2 grams of methane at 1 atmosphere and 60°F).

recovered, because pre-mining drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Another advantage is that pre-mining drainage greatly improves safety conditions for miners, because the risks of explosion from unsafe methane levels are greatly reduced. A disadvantage of this method is that it may be difficult for some mines to plan where they will mine many years in advance of the actual mining.

- **Gob wells**. The fractured zone caused by the collapse of the strata surrounding the mined coal seam in an underground mine is known as a "gob" area; this area is a significant source of methane. Gob wells are drilled from the surface to a point just above the coal seam. As mining advances under the well, the methane-charged coal and strata around the well fractures. The methane emitted from this fractured area flows into the gob well and up to the surface. Initially, gob wells produce nearly pure methane. Over time, however, ventilation air from mine working areas may flow into the gob area and dilute the methane. It is possible to recover from 30 to over 50 percent of the methane that would otherwise be emitted is possible with this approach.

- **In-mine horizontal boreholes**. In-mine boreholes are drilled inside the mine (as opposed to from the surface), and they operate to drain methane from unmined areas of the coal seam shortly before mining. The recovery efficiency of this technique is low—approximately 10 to 20 percent of methane that would otherwise be emitted. However, the methane produced is typically over 95 percent pure.

Options for utilizing recovered methane include the following:

- **Injecting methane into a pipeline**. This option currently requires that a nearly pure methane be recovered. Gathering lines must be built from the mine to a commercial pipeline.

- **Utilizing methane as a fuel in a turbine or engine**. Under this option, recovered methane is fed into an on-site generator. The electricity generated may be used to meet the potentially significant electricity requirements of the mine. Electricity generated in excess of the mine's on-site needs may be sold to a utility. As opposed to pipeline injection, methane that has been mixed with mine ventilation air may be used for power generation. Power generation is a technically viable option for methane concentrations as low as 30 percent.

- **Co-firing methane in a boiler**. Here, methane is utilized in conjunction with another fuel source in a nearby boiler, such as one used on-site for coal drying.

- **Selling low Btu gas to industrial users**. This option involves selling recovered methane that has been mixed with mine air (gob gas) to a nearby industrial user.

For many mines, development of recovery projects can be a profitable undertaking, due to the energy value of the recovered gas. Currently, 11 U.S. mines have developed projects in which they are selling recovered methane to pipeline companies. A large portion of these cost-effective emissions reductions could be achieved at the large and gassy underground mines located in the Appalachian basins. The extent to which these emissions reductions can be achieved is dependent, in part, on the removal of several existing informational, legal, institutional, and regulatory barriers.

E.2.2 Emerging Technologies

In addition to the methods described above, a number of new or improved technologies and practices for reducing methane emissions are being developed.

One technology currently under development is to enrich gob gas to pipeline quality by using technologies that separate methane molecules from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research.

In addition to the highly concentrated methane produced by degasification systems, the methane emitted in low concentrations in ventilation air also could be utilized. Ventilation air may be used as the combustion air in an on-site turbine or mine-mouth coal fired boiler. However, at the current time, utilization of ventilation air has not been technically demonstrated.

Finally, in cases where it is not possible to utilize methane as an energy source, the gas could be flared, which involves burning the methane so that primarily carbon dioxide, rather than methane, is emitted. Currently, flaring is not considered to be a feasible option for coal mines because of safety considerations, although research on this topic is being conducted. (The Energy Policy Act of 1992 includes a provision for further study of this approach.)

E.3 Related Regulations and Programs

E.3.1 EPA's Coalbed Methane Outreach Program

Under the Climate Change Action Plan,[a] the U.S. EPA is developing the Coalbed Methane Outreach Program to promote the use of cost-effective techniques for reducing methane emissions from coal mining. The program is focusing on large gassy coal mines that are likely candidates for profitable methane recovery and utilization. As a result of the program, additional coal mines are expected to recover and utilize coalbed methane. Activities taken in response to this program may be reported under Section 1605(b).

(a) The Climate Change Action Plan, put forward by the Federal Government in October 1993, aims to address the challenge of global warming with cost-effective emission reduction initiatives. The goal of the Plan is to return U.S. greenhouse gas emissions to 1990 levels by the year 2000.

E.3.2 Other Existing Regulations and Programs

State and federal regulations concerning the release of coal mine methane have been developed solely as a result of safety, rather than environmental, concerns. The principal regulatory body responsible for ensuring the safety of mining operations is the U.S. Mining Safety and Health Administration (MSHA). All underground coal mines in the United States are required to have an MSHA approved mine ventilation plan that can reliably maintain methane concentrations of less than 1 percent in air. To the extent that a mine plans to use mine degasification to control some of its methane liberations, these approaches must be incorporated into the mine ventilation plans approved by MSHA. MSHA is also responsible for measuring methane levels in ventilation air streams in underground coal mines. MSHA records of methane concentrations could be used to validate reported emissions reductions. Thus, it would not be necessary to set up a separate methane measurement program as part of the 1605(b) reporting requirements.

Once the methane is recovered, few regulations or programs govern its use. In fact, as mentioned previously, in some key states (such as West Virginia and Pennsylvania) uncertain coalbed methane ownership currently poses a major barrier to the development of methane utilization projects.

E.4 References

DOE/EIA (Department of Energy/Energy Information Agency). 1992. Coal Production 1991. U.S. Department of Energy, Washington, DC. October 1992. DOE/EIA-0118(91)

DOE/EIA (Department of Energy/Energy Information Agency). 1993. The Changing Structure of the U.S. Coal Industry: An Update. U.S. Department of Energy, Washington, DC. July 1993. DOE/EIA-0513(93)

IPCC (Intergovernmental Panel on Climate Change). 1992. *Climate Change 1992: The Supplementary Report to the IPCC Scientific Assessment*. Report Prepared for the Intergovernmental Panel on Climate Change by Working Group 1.

USEPA (U.S. Environmental Protection Agency). 1993a. *Anthropogenic Methane Emissions in the United States*, Report to the Congress, prepared by the Global Change Division, Office of Air and Radiation, EPA, Washington, DC.

USEPA (U.S. Environmental Protection Agency). 1993b. *Opportunities to Reduce Anthropogenic Methane Emissions in the United States*, Report to the Congress, prepared by the Global Change Division, Office of Air and Radiation, EPA, Washington, DC.

Appendix 3.F

Nitrous Oxide Emissions and Emissions Reductions in the Adipic Acid Production Industry

Nitrous Oxide Emissions and Emissions Reductions in the Adipic Acid Production Industry

This appendix presents background information on the adipic acid production industry, a brief summary of promising emissions reduction options, and a description of related regulations and programs.

F.1 Industry Background

A recent investigation by Thiemens and Trogler suggested that the production of adipic acid may be a small but significant source of anthropogenic nitrous oxide (N_2O) emissions into the atmosphere (Thiemens and Trogler 1991). Adipic acid, principally used in the manufacture of nylon (nylon-6,6), is formed by the oxidation of nitric acid with ketone-alcohol (cyclohexanol). During the adipic acid production process, N_2O is produced as a waste gas. Adipic acid is also used in the production of plasticizers, low temperature lubricants, polyurethanes, and food products (Radian 1992).

In the United States, adipic acid is produced by three companies in four locations: Allied Chemicals in Hopewell, Virginia; DuPont in Orange and Victoria, Texas; and Monsanto in Pensacola, Florida. These four plants have a 1990 combined production capacity of about 800 million kilograms (1.77 billion pounds). U.S adipic acid demand in 1989 and 1990 was estimated at 714 to 744 million kg (1.57 to 1.64 billion pounds) per year. The bulk price of adipic acid in 1990 was estimated at about $1.32 per kg ($0.60 per pound). About 90 percent of the current U.S. adipic acid demand is used for nylon production.

Air emissions of N_2O in the United States are not regulated, and very little emissions data have been made public. However, based on the available overall reaction stoichiometry for adipic acid production, it is estimated that about one mole of nitrous oxide is generated per mole of acid produced, or approximately 0.3 kg of nitrous oxide for every kilogram of adipic acid produced.

Nitrous oxide emissions from adipic acid production can be reduced by collecting or destroying the gas. Efforts are underway by U.S. manufacturers to develop and implement the most cost effective techniques for reducing the emissions. The Monsanto and DuPont Victoria, Texas plants currently thermally decompose the N_2O created in the production process, with a reported control efficiency of 98 percent.

Although thermal decomposition of N_2O is effective, its energy requirements are substantial. In addition, it produces NO_x emissions, which are also undesirable. Other promising alternatives being investigated by adipic acid manufacturers include conversion of N_2O to NO for recovery/reuse in the nitric acid production process; and catalytic decomposition of N_2O to N_2, O_2, and a small amount of residual NO_x.

The conversion of N_2O to NO for recovery/reuse offers substantial energy savings over the thermal decomposition process. However, to take advantage of the NO that is produced, the adipic acid production facility must be co-located with a nitric acid production facility. The capital cost for this option is estimated to be about $20 million for a plant similar in capacity to DuPont's Victoria, Texas, plant, which is the largest such plant in the United States.

Catalytic decomposition of N_2O has lower capital costs and does not need to be located near a nitric acid production facility. However, NO_x emissions would need to be controlled, which would add to the cost. A catalyst-based system, for use in conjunction with NO_x controls, is estimated to have a $5 to $10 million capital cost for a plant similar to DuPont's Victoria, Texas, plant. The NO_x controls would add an estimated $10 million in capital costs. This NO_x control cost may be less if the controls were designed as an integrated part of a new facility.

The production of nitric acid, an input to the adipic acid production process, also produces N_2O emissions. However, less information is currently available on these emissions, and additional research is warranted. At this time, the guidance for reporting emissions reductions from adipic acid production is believed to be applicable for emissions reductions from nitric acid production as well.

Finally, it has been reported that an alternative production process for nylon used by at least one manufacturer in the U.S. also produces a small amount of N_2O emissions. While it appears possible to reduce these emissions as well, additional research is needed to address this source.

F.2 Related Regulations and Programs

There are no N_2O emissions regulations in the U.S. However, over the past several years, U.S. adipic acid producers have committed to voluntarily controlling emissions. The voluntary reporting guidelines allow reporting of emissions reductions with information that is expected to be generated as part of currently planned efforts.

For example, DuPont has set a company goal of eliminating N_2O emissions from its adipic acid production facilities by 1996. It is investigating recovery/reuse at its Victoria, Texas, plant, and catalytic decomposition options for the Orange, Texas plant. DuPont is also holding discussions with other key manufacturers of adipic acid world-wide on technologies that can achieve emissions reduction goals, and has offered to share its technologies. European companies that have participated in the technology discussions include ICI, BASF, and Rhône-Poulenc. The *European Chemical News* reported that a commitment to cut emissions within five years has been agreed upon by the discussion participants (ECN 1991).

In addition to DuPont's efforts, Monsanto is currently thermally decomposing N_2O at its Pensacola, Florida plant. A recent report for the U.S. EPA estimated U.S. 1990 N_2O emissions from all four U.S. adipic acid manufacturing plants to be about 62 million kilograms (Radian 1992). The effects of the existing DuPont and Monsanto control programs are therefore substantial in that uncontrolled emissions are estimated at over 200 million kilograms based on the stoichiometric balance of the production process.

F.3 References

ECN (European Chemical News). 1991. "Adipic acid firms move to curb "new" ozone depleter," *European Chemical News*, March 11, 1991, p. 41.

Radian Corporation. 1992. *Nitrous Oxide Emissions from Adipic Acid Manufacturing: Final Report*, prepared for the Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, N.C., January 1992.

Thiemens, M.H. and W.C. Trogler. 1991. "Nylon production: An unknown source of atmospheric nitrous oxide," *Science*, Vol. 251, February 22, 1991, pp. 932-934.

Appendix A

Conversion Factors for Standard Units

This appendix has been prepared in consistent metric units based on the *Le Systéme International d'Unités* (SI). Some important features of the SI are summarized in this appendix along with a summary of factors to enable readers to convert to English units.

Table A.1. SI Derived Units

Quantity	Unit	Symbol
Energy, work, heat[a]	joule	J
Power, radiant flux	watt	W
Electric potential	volt	V
Electric resistance	ohm	R
Conductance	siemans	S

(a) An energy unit accepted for limited use is the kilowatthour (kWh). 1 kWh = 1,000 Wh = 3.6 MJ.

Table A.2. SI Prefixes

Prefix	Symbol	Multiplication Factor
exa	E	10^{18}
peta	P	10^{15}
tera	T	10^{12}
giga	G	10^{9}
mega	M	10^{6}
kilo	k	10^{3}

Table A.3. SI Area and Mass Units

Quantity	Unit	Symbol
Area		
Square meter	1 m^2	m^2
Hectare	10,000 m^2	ha
Million hectares	10^6 ha	Mha
Mass		
Metric ton	10^3 kg	t
Gigagram	10^9 g	Gg
Million metric tons	10^6 t	Mt
Giga ton	10^9 t	Gt

Table A.4. Conversion of Metric Units to English Units

To convert from	to	multiply by
Basic units		
Area		
hectares (ha)	acres	2.471
Mass		
kilograms (kg)	pounds (mass)	2.205
metric tons (t)	short ton (2,000 lb)	1.102
gigagrams (Gg)	short ton (2,000 lb)	1.102×10^3
Energy		
kilojoules (kJ)	British thermal units (Btus)	0.9478
exajoules (EJ)	quad (10^{15} Btus)	0.9478
petajoules (PJ)	quad (10^{15} Btus)	0.9478×10^{-3}
Special Units		
Carbon		
kg carbon (kg C)	lb CO_2	8.084
Crop production		
metric t (corn)	bushel (56 lb)	39.37
metric t (soybeans)	bushel (60 lb)	36.74
metric t (wheat)	bushel (60 lb)	36.74
Crop yield		
kg/ha	lb/acre	0.8922
metric t/ha	short ton/acre	0.4461
metric t/ha (corn)	bushels (56 lb)/acre	15.93
metric t/ha (soybeans)	bushels (60 lb)/acre	14.87
metric t/ha (wheat)	bushels (60 lb)/acre	14.87

Appendix B

Emissions Factors

Table B.1. Factors: Carbon Coefficients and Assumptions

Fuel Type	Million Short Tons Carbon Dioxide per Quadrillion Btu	Million Metric Tons Carbon Dioxide per Quadrillion Btu[a]
Petroleum		
Motor Gasoline	77.7	70.5
LPG	69.1	62.7
Jet Fuel	77.9	70.7
Distillate Fuel	79.9	72.5
Residual Fuel	86.6	78.6
Asphalt and Road Oil[b]	84.2	76.4
Lubricants[b]	84.9	77.0
Petrochemical Feed	77.8	70.6
Aviation Gas[b]	77.7	70.5
Kerosene	77.9	70.7
Petroleum Coke[b]	109.2	99.1
Special Naphtha[b]	77.7	70.5
Other: Waxes and Miscellaneous[b]	84.2	76.4
Coal[c]		
Anthracite Coal	112.5	102.1
Bituminous Coal	101.5	92.1
Subbituminous Coal	105.0	95.3
Lignite	106.5	96.6
Natural Gas		
Flare Gas[b]	60.8	55.2
Natural Gas	58.2	52.8

(a) Assumes conversion of 1 quadrillion Btu = 1.0551 exajoules and fraction combusted = 99 percent.
(b) Emissions coefficients are EIA estimates based on underlying chemical composition of the product.
(c) Coal emissions factor is for 1990: varies by $\pm$0.2 percent in other years.
NA = not available.

Source: U.S. Department of Energy, Energy Information Administration. 1993. Table 11 in *Emissions of Greenhouse Gases in the United States 1985-1990*. DOE/EIA-0573. U.S. Government Printing Office, Washington, DC.

Appendix C

Adjusted Electricity Emissions Factors by State

Use of the State-Level Electricity Emissions Factors

The default emissions factors contained in this appendix are the simplest to use relative to other methods of calculating emissions. However, you should realize that these default factors will either underestimate or overestimate the actual emissions characteristics of any given power-generating equipment, as they represent the average emissions characteristics over a state. If available, you are encouraged to use emissions factors specific to your reported project, for example, a utility-specific factor that has incorporated actual fuel mix and dispatching modes.

For the purposes of the voluntary reporting program, and to retain flexibility and ease-of-use, Appendix C provides default state-level electrical emissions factors for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Three factors are given for each state: one for emissions from utility generation, one for emissions from nonutility generation, and one combined utility/nonutility. If you know the source for your electricity (that is, utility or nonutility), you may use the appropriate factor. If you do not know or if you use both utility and nonutility sources, you should use the combined factors for your state.

Table C.1. Adjusted Electricity Emissions Factors by State

REGION	STATE	UTILITY		NUG		COMBINED			UTILITY	NUG	UTILITY	NUG	COMBINED	
		CO2 Emissions Factor (short ton/MWh)	CO2 Emissions Factor (lbs/MWh)	Weighted CO2 Emissions Factor (short ton/MWh)	Weighted CO2 Emissions Factor (lbs/MWh)	CO2 Emissions Factor (short ton/MWh)	CO2 Emissions Factor (lbs/MWh)	CO2 Emissions Factor (metric ton/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)
New England	Connecticut	0.262	523	1.005	2010	0.358	715	0.324	0.037	0.290	0.005	0.052	0.0683	0.0104
	Maine	0.126	251	1.157	2314	0.483	966	0.438	0.000	0.351	0.000	0.054	0.1170	0.0180
	Massachusetts	0.711	1,422	0.824	1647	0.729	1459	0.662	0.118	0.184	0.021	0.056	0.1281	0.0266
	New Hampshire	0.340	680	1.283	2567	0.426	852	0.386	0.081	0.395	0.010	0.063	0.1077	0.0145
	Rhode Island	0.917	1,835	0.537	1074	0.546	1091	0.495	0.020	0.066	0.019	0.049	0.0644	0.0487
	Vermont	0.066	131	0.586	1173	0.080	159	0.072	0.011	0.182	0.003	0.030	0.0152	0.0041
Mid Atlantic	New Jersey	0.302	605	0.616	1232	0.387	774	0.351	0.065	0.097	0.015	0.051	0.0731	0.0241
	New York	0.493	986	0.763	1527	0.518	1036	0.470	0.076	0.186	0.018	0.048	0.0859	0.0208
	Pennsylvania	0.627	1,254	0.917	1835	0.643	1286	0.583	0.209	0.274	0.025	0.046	0.2128	0.0259
East-North Central	Illinois	0.432	865	0.814	1628	0.433	866	0.393	0.136	0.227	0.016	0.046	0.1360	0.0164
	Indiana	1.086	2,171	0.633	1267	1.086	2171	0.985	0.335	0.126	0.040	0.044	0.3346	0.0398
	Michigan	0.792	1,584	0.756	1511	0.788	1576	0.715	0.253	0.168	0.031	0.052	0.2450	0.0327
	Ohio	0.903	1,807	1.111	2222	0.904	1807	0.820	0.302	0.344	0.036	0.053	0.3020	0.0355
	Wisconsin	0.664	1,329	1.063	2125	0.671	1343	0.609	0.241	0.336	0.029	0.049	0.2430	0.0292
West-North Central	Iowa	0.842	1,685	0.943	1885	0.843	1686	0.765	0.288	0.319	0.034	0.040	0.2878	0.0342
	Kansas	0.852	1,703	0.513	1027	0.852	1703	0.773	0.239	0.055	0.030	0.047	0.2386	0.0302
	Minnesota	0.810	1,619	1.018	2035	0.814	1627	0.738	0.226	0.322	0.027	0.049	0.2278	0.0276
	Missouri	0.891	1,783	0.907	1815	0.891	1783	0.809	0.281	0.293	0.033	0.041	0.2814	0.0334
	Nebraska	0.644	1,288	N/A	N/A	0.644	1288	0.580	0.189	N/A	0.023	N/A	0.189	0.023
	North Dakota	1.152	2,303	0.794	1589	1.151	2303	1.045	0.319	0.222	0.038	0.041	0.3194	0.0376
	South Dakota	0.456	912	N/A	N/A	0.456	912	0.410	0.143	N/A	0.017	N/A	0.143	0.017
South Atlantic	Delaware	0.933	1,865	0.735	1470	0.928	1855	0.842	0.217	0.171	0.034	0.029	0.2161	0.0344
	District of Columbia	1.324	2,649	N/A	N/A	1.324	2649	1.192	0.048	N/A	0.005	N/A	0.048	0.005
	Florida	0.633	1,266	1.144	2288	0.647	1294	0.587	0.159	0.340	0.027	0.058	0.1640	0.0275
	Georgia	0.609	1,218	1.333	2665	0.610	1220	0.553	0.216	0.395	0.025	0.066	0.2160	0.0255
	Maryland	0.675	1,350	1.005	2011	0.678	1356	0.615	0.205	0.263	0.026	0.057	0.2051	0.0260
	North Carolina	0.650	1,300	1.138	2276	0.675	1350	0.612	0.222	0.371	0.026	0.050	0.2290	0.0276
	South Carolina	0.332	665	1.439	2878	0.344	688	0.312	0.110	0.447	0.013	0.070	0.1130	0.0136
	Virginia	0.488	977	1.101	2202	0.554	1107	0.502	0.163	0.336	0.022	0.053	0.1805	0.0253
	West Virginia	1.007	2,013	0.645	1290	1.003	2005	0.909	0.337	0.208	0.040	0.029	0.3356	0.0396

Table C.1. Adjusted Electricity Emissions Factors by State

		UTILITY		NUG		COMBINED			UTILITY	NUG	UTILITY	NUG	COMBINED	
REGION	STATE	CO2 Emissions Factor (short ton/MWh)	CO2 Emissions Factor (lbs/MWh)	Weighted CO2 Emissions Factor (short ton/MWh)	Weighted CO2 Emissions Factor (lbs/MWh)	CO2 Emissions Factor (short ton/MWh)	CO2 Emissions Factor (lbs/MWh)	CO2 Emissions Factor (metric ton/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)	Weighted N20 Emissions Factor (lbs/MWh)	Weighted CH4 Emissions Factor (lbs/MWh)
East-South Central	Alabama	0.683	1,367	1.258	2515	0.684	1369	0.621	0.227	0.358	0.027	0.068	0.2277	0.0271
	Kentucky	0.965	1,930	N/A	N/A	0.965	1930	0.869	0.323	N/A	0.038	N/A	0.323	0.038
	Mississippi	0.533	1,066	1.487	2973	0.537	1075	0.487	0.137	0.439	0.029	0.079	0.1382	0.0290
	Tennessee	0.667	1,334	1.066	2131	0.668	1335	0.606	0.226	0.342	0.027	0.050	0.2259	0.0266
West-South Central	Arkansas	0.642	1,284	1.293	2586	0.643	1286	0.584	0.182	0.364	0.025	0.073	0.1825	0.0250
	Louisiana	0.695	1,390	0.674	1348	0.694	1388	0.629	0.125	0.129	0.038	0.050	0.1248	0.0385
	Oklahoma	0.834	1,667	0.867	1735	0.836	1672	0.758	0.219	0.252	0.047	0.046	0.2211	0.0470
	Texas	0.798	1,596	0.576	1151	0.776	1552	0.704	0.172	0.087	0.041	0.048	0.1637	0.0413
Mountain	Arizona	0.399	797	1.140	2281	0.399	798	0.362	0.171	0.349	0.023	0.054	0.1709	0.0232
	Colorado	1.015	2,030	0.582	1164	1.000	2001	0.908	0.320	0.114	0.038	0.044	0.3137	0.0385
	Idaho	0.000	0	0.874	1748	0.134	269	0.122	0.000	0.261	0.000	0.046	0.0382	0.0067
	Montana	0.774	1,548	0.950	1899	0.777	1553	0.704	0.230	0.319	0.027	0.041	0.2317	0.0276
	Nevada	1.011	2,021	0.257	515	0.937	1875	0.850	0.268	0.029	0.037	0.024	0.2457	0.0360
	New Mexico	0.703	1,405	0.587	1174	0.703	1405	0.637	0.311	0.087	0.040	0.054	0.3111	0.0404
	Utah	0.996	1,991	0.494	988	0.995	1990	0.903	0.329	0.062	0.040	0.047	0.3283	0.0399
	Wyoming	1.097	2,194	0.633	1267	1.097	2194	0.995	0.334	0.149	0.039	0.043	0.3343	0.0393
Pacific Contiguous	California	0.287	573	0.593	1186	0.378	756	0.343	0.004	0.123	0.027	0.042	0.0392	0.0315
	Oregon	0.097	195	1.309	2618	0.118	235	0.107	0.039	0.400	0.009	0.066	0.0448	0.0102
	Washington	0.138	276	0.915	1831	0.153	306	0.139	0.043	0.241	0.006	0.055	0.0461	0.0069
Pacific Non-contiguous	Alaska	0.000	1	0.834	1667	0.016	31	0.014	0.173	0.201	0.091	0.049	0.1732	0.0907
	Hawaii	0.700	1,399	0.943	1886	0.757	1514	0.687	0.042	0.248	0.005	0.036	0.0888	0.0120
	U.S. Mean	0.648	1,296	0.896	1792	0.646	1291	0.586	0.179	0.245	0.026	0.050	0.1872	0.0291

Methodology Used to Develop Electricity Emissions Factors by State

C.1 Utility CO_2 Emissions Factors

To arrive at the carbon dioxide emissions factors in pounds per megawatt hour (lb/MWh), for each state, carbon dioxide emissions for 1992 in thousand short tons were converted to pounds (short tons multiplied by 2,000 pounds), then divided by 1992 net generation in million kilowatt hours (10^6 kWh). (Since these factors are principally for use by consumers of electricity, gross generation is not used.) The resultant value was then multiplied by 1,000 to convert pounds per kilowatt hour to pounds per megawatt hour. Because transmission and distribution losses have not been included, the emissions factors are considered conservative.

Example: State of Wisconsin

CO_2 Emissions = $30,867 \times 10^3$ short tons
= $30,867 \times 10^3$ short tons • 2,000 lb = $61,734 \times 10^6$ lb

Net Generation = $46,464 \times 10^6$ kWh

CO_2 Emission Factor = $61,734 \times 10^6$ lb/$46,464 \times 10^6$ kWh = 1,329 lbs/MWh

Source: DOE/EIA 1994, Table 46, third column, Electric Utility CO_2 Emissions in thousand short tons and Table 12, first column, Electric Utility Net Generation in million kilowatthours.

C.2 Utility Methane and Nitrous Oxide Emissions Factors

The utility weighted non-CO_2 emissions factors were calculated by assigning representative technologies to each energy source. These representative technologies for each energy source were compiled from 1992 information collected by the Energy Information Administration. The emissions factors (in pounds per megawatt hour), developed by NREL (1993), DOE (1991), WAPA (1994), and IPCC (1991), for these technologies were multiplied by the 1992 net generation (in millions of kilowatt hours) to give pounds of methane and nitrous oxide emissions. Finally, the pounds of methane and nitrous oxide emissions from each energy source were added and the sum divided by the total net generation. (See the example below, computing the nitrous oxide emissions factor for the state of Wisconsin.)

Example: Weighted N_20 Emissions Factor for the State of Wisconsin for 1992

Technology	Net Generation (10^3 MWh)	N_20 Emissions Factor (lbs/MWh)	Estimated N_20 Emissions (thousand lbs)
Coal - Pulverized	32,741	0.34	11,131.94
Nuclear/Other	11,207	0.00	0.00
Hydroelectric	2,123	0.00	0.00
Wood - Steam Turbine	133	0.55	73.15
Municipal Solid Waste - Steam Turbine	16	0.55	8.80
Gas - Steam Turbine	173	0.00	0.00
Gas - Combustion Turbine	15	0.24	3.6
Oil - Steam Turbine	53	0.00	0.00
Oil - Combustion Turbine	2	0.276	0.55
Total	46,464		11,218.04

Weighted N_20 Emissions Factor for State of Wisconsin for 1992:

$[(11{,}218.04 \times 10^3 \text{ lbs of } N_20)/(46{,}464 \times 10^6 \text{ kWh})] \bullet 10^3 \text{ kWh/MWh} = \underline{0.241 \text{ lbs/MWh}}$

Sources: DOE/EIA 1994, Tables 13, 14, and 15; Energy Information Administration, Monthly

C.3 Nonutility CO_2 and Non-CO_2 Weighted Emissions Factors Calculation

The weighted emissions factors for nonutility generators were calculated as outlined above for utility non-carbon dioxide emission factors, based on "bottom-up" (technology) methodology. The emissions factors for each technology are listed in the Emissions Factors for Selected Technologies table below.

Deliveries data in millions of kilowatt hours were used to account for sales, interchanges, and exchanges of electric energy with utilities and other nonutilities.

Source: DOE/EIA 1994, Tables 79 and 82.

Emissions Factors for Selected Technologies

Technology	CO_2 Emissions Factor (lbs/MWh)	N_2O Emissions Factor (lbs/MWh)	CH_4 Emissions Factor (lbs/MWh)
Coal - Pulverized	1,970	0.34	0.04
Nuclear/Other	0.00	0.00	0.00
Hydroelectric	0.00	0.00	0.00
Wood Waste Biomass Boiler	3,400	0.55	0.14
Municipal Solid Waste Boiler	3,747	0.55	0.02
Gas - Steam Turbine	968	0.00	0.05
Gas - Combustion Turbine	1,560	0.24	0.16
Gas- Combined Cycle	952	0.063	0.015
Oil - Steam Turbine	1,452	0.00	0.002
Oil - Combustion Turbine	2,150	0.276	0.021
Oil- Combined Cycle	1,330	0.268	0.013
Renewables	0.00	0.00	0.00
Sources: WAPA 1994; DOE 1991; NREL 1993; IPCC 1991.			

C.4 Combined Emissions Factors

To calculate combined CO_2, N_2O, and CH_4 utility/nonutility factors, the sum of utility and non-utility CO_2 emissions was divided by the sum of utility and nonutility generation.

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Appendix D

Conversion of Carbon to Carbon Dioxide Emissions

Conversion of Carbon to Carbon Dioxide Emissions

Many times project analysis starts with data on the carbon content of fuels or the release of carbon from sinks. This means that the analysis may end with a result expressed in terms of carbon emissions or carbon capture. However, the EPAct 1605(b) voluntary reporting program requires that reports be expressed in terms of greenhouse gases—that is, carbon dioxide.

The conversion of quantities of carbon to quantities of carbon dioxide is simple. The atomic weight of carbon is 12. The atomic weight of oxygen is 16. Hence, the molecular weight of carbon dioxide (carbon dioxide) is 44 (one atom of carbon, 12, plus two atoms of oxygen, 32). This means that 12 grams (or pounds or tons) of carbon released as carbon dioxide is associated with 44 grams (or pounds or tons) of carbon dioxide. Therefore, the conversion from carbon released to carbon dioxide emissions can be expressed as follows:

$$\text{Weight of } CO_2 = 44/12 \text{ weight of carbon} = 3.67 \text{ weight of carbon}$$

Appendix E

Reportable Greenhouse Gases for Which Global Warming Potentials Have Been Developed

Reportable Greenhouse Gases for Which Global Warming Potentials Have Been Developed

A Global Warming Potential (GWP) is a measure, or index, of the impact that each gas has on global warming relative to the effect that carbon dioxide has. So, for example, if a kilogram of a certain gas has a GWP of 2, that kilogram of that gas is expected to have twice as much effect on global warming as a kilogram of carbon dioxide. Using GWPs helps decision-makers (for example, in utilities or industry) and policymakers put different greenhouse gases on an equivalent scale to perform a wide variety of analyses:

- performing cost-benefit analyses of various candidate projects to reduce greenhouse gas emissions
- assessing the relative contributions of the many human activities contributing to greenhouse gas emissions
- comparing (and ranking) climate effects from competing technologies and energy uses, including consideration of different energy policies
- developing approaches to minimize the impact of human activities on the climate system
- comparing the global climate change contributions of various countries
- functioning as a signal to policymakers for encouraging some activities and discouraging others
- determining approaches most appropriate for industries and governments to meet commitments to help reduce the radiative forcing on climate from increasing concentrations and emissions of greenhouse gases.

Several factors affect the GWP value for any particular gas. Gases that have large immediate warming effects (instantaneous radiative forcing) will generally have higher GWPs. However, the effects of greenhouse gases are realized over a period of time, so the second important factor in calculating a GWP is the length of time the gas stays in the atmosphere (atmospheric lifetime). Generally, gases with longer atmospheric lifetimes will have higher GWPs than gases with shorter lifetimes. Finally, some gases interact with other gases in the atmosphere (indirect effects) to either increase or decrease the impact of the gases.

The GWPs listed in Table E.1 were developed recently for the Intergovernmental Panel on Climate Change (IPCC 1994). This list will replace GWPs developed previously (IPCC 1990, 1992); as the science continues to evolve, the gases and the values will likely be revised again. Because of the difficulty in modeling the interactions of the various gases, these GWPs do not include indirect effects except where noted. (See, for example, methane.)

Table E.1 actually contains three sets of GWPs, each set calculated over a different time period. The GWP calculated for 20 years provides a comparison of the effects of gases in the relatively near future. In contrast, the 500-year index will give a relatively higher GWP values to long-lived gases than the 20-year GWP values.

As you use these GWPs, remember the limitations of such a measure. First, for most gases the GWPs do not account for indirect effects. So, for example, while CFC-11 appears to be 5,000 times as potent a greenhouse gas as carbon dioxide over the short term, its indirect effects may entirely negate its direct effects. This possibility is not reflected in the GWP index. Second, the modeling of atmospheric chemistry is rapidly changing. These GWPs are significantly different from those used by the IPCC two years ago, and they will probably be revised again. Third, these GWPs rest on an assumption that the background concentration of carbon dioxide is stable and that the atmospheric system is in equilibrium. This assumption is clearly unrealistic, though it helps to provide consistency in making assessments.

Table E.1. Direct Global Warming Potentials[a]

Species	Chemical Formula	Atmospheric Lifetime (years)	Global Warming Potential (Time Horizon)		
			20 years	100 years	500 years
CO_2	CO_2	(b)	1	1	1
CFCs					
CFC-11	$CFCl_3$	50±5	5000	3900	1400
CFC-12	CF_2Cl_2	102	8000	8300	4000
CFC-13	$CClF_3$	640	8700	12100	13800
CFC-113	$C_2F_3Cl_3$	85	5100	4900	2200
CFC-114	$C_2F_4Cl_2$	300	7000	9100	7900
CFC-115	C_2F_5Cl	1700	6300	9100	12400
HCFCS, etc.					
HCFC-22	CF_2HCl	13.3	4300	1600	500
HCFC-123	$C_2F_3HCl_2$	1.4	310	90	30
HCFC-124	C_2F_4HCl	5.9	1500	470	140
HCFC-141b	$C_2FH_2Cl_3$	9.4	1800	620	190
HCFC-142b	$C_2F_2H_3Cl$	19.5	4300	2000	600
HCFC-225CA	$C_3F_5HCl_2$	2.5	590	180	50
HCFC-225CB	$C_3F_5HCl_2$	6.6	1800	570	170
Carbon Tetrachloride	CCl_4	42	2000	1400	480
Methyl Chloroform	CH_3CCl_3	5.4±0.4	360	110	30
Bromocarbons[f]					
H-1301	CF_3Br	65	6300	5500	2100
Other					
HFC-23	CHF_3	390	9500	12700	12400
HFC-32	CH_2F_2	6	1900	570	180
HFC-43-10mee		20.8	3400	1600	490
HFC-125	C_2HF_5	36.0	5000	3200	1100
HFC-134	$C_2H_2F_4$	11.9	3200	1160	350
HFC-134a	CH_2FCF_3	17.7	3800	1700	510
HFC-152a	$C_2H_4F_2$	1.5	440	130	40
HFC-143a	$C_2H_3F_3$	55	5300	4300	1600

Table E.1. (cont'd)

Species	Chemical Formula	Atmospheric Lifetime (years)	Global Warming Potential (Time Horizon)		
			20 years	100 years	500 years
HFC-227ea	C_3HF_7	43.0	4800	3300	1100
HFC-236fa	$C_3H_2F_6$	265	6200	7900	6500
HFC-245ca	$C_3H_3F_5$	1.0	300	90	30
HFC-245ca	$C_3H_3F_5$	9.2	2400	790	240
Chloroform	$CHCl_3$	0.55	20	5	1
Methylene chloride	CH_2Cl_2	0.41	30	10	3
Sulfur hexafluoride	SF_6	3200	9300	13600	19500
Perfluoromethane	CF_4	50000	2700	4000	6100
Perfluoroethane	C_2F_6	10000	6100	9000	13500
Perfluorocyclo-butane	$c\text{-}C_4F_8$	3200	6100	8900	12800
Perfluorohexane	C_6F_{14}	3200	5600	8900	17800
Methane[(c)]	CH_4	12-18[(d)]	56-110	19-43	9-16
Nitrous oxide	N_2O	121	290	320	170
Trifluoroiodo-methane	CF_3I	<0.005	<6	$<<1$	$<<<1$
Carbon monoxide[(e)]	CO	months	+	+	+
Nonmethane hydrocarbons[(e)]	NMHCs	days to months	+	+	+
Nitrous oxides[(e)]	NO_x	days	+	+	+

(a) Referenced to the AGWP for the Bern carbon cycle model CO_2 decay response and future CO_2 atmospheric concentrations held constant at current levels (based on IPCC 1994 and WMO 1994).
(b) Decay of CO_2 is a complex function of the carbon cycle.
(c) Includes direct and indirect components.
(d) Includes the dependence of the residence time on CH_4 abundance.
(e) GWPs for indirect effects involving emissions from short-lived gases are particularly difficult to evaluate, though the sign of these three types is expected to be positive.
(f) You may report other halogenated substances, such as H-1211 and H-2402, that are not listed in this table and for which the IPCC has not developed an estimate of global warming potential.

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